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NSP Revision (REV) No.	NRC T.S. Change No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
ORIGINAL	-	8/9/73	-	-	Issued Appendix A & B Tech Specs for DPR-42
-	NOTE 1	12/14/73	1	-	90% power authorized for Unit 1
1	1	11/29/73	NOTE 2	-	Ventilation systems performance
2	2	4/2/74	NOTE 2	-	Appendix B revision
-	3	4/5/74	2	-	100% power authorized for Unit 1
-	NOTE 1	7/18/74	3	-	Authorized Cf-252 source
3	4	9/16/74	4	-	Ventilation performance
4	5	10/15/74	5	-	Inservice inspection of SG tubes
5	6	10/25/74	6	-	Clarify Intent
-	-	10/29/74	-	-	Issued Appendix A & B Tech Specs for DPR-60
-	-	5/29/75	-	1	Authorized Na-24 source
6	8	6/11/75	8	3	Accumulator requirements
7	7	7/18/75	7	2	Inservice inspection of SG tubes
8	NOTE 3	1/23/76	9	4	Reporting requirements
9	-	2/6/76	10	-	Turbine SV Testing Waiver

NOTES:

1. License Amendment not affecting the Technical Specifications.
2. Technical Specification change issued prior to 10CFR Revisions which require them to be issued as License Amendments.
3. Technical Specification changes not assigned a Technical Specification Change Number following Technical Specification Change No. 7.

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10	5/10/76	13	7	Organization/SAC Role
11	5/11/76	12	6	Source, byproduct, and special nuclear material
12	7/9/76	11	5	Radioactive effluent Limits/REMP
13	8/11/76	14	8	Safety related snubbers
14	8/11/76	15	9	Refueling test interval (Unit 2)
-	8/27/76	NOTE 1	-	License modification requiring ECCS re-evaluation
15	10/4/76	16	10	Power distribution limits
16	10/14/76	17	11	Filter systems surveillance
17	3/11/77	18	12	Revision to Appendix B Tech Specs
-	3/11/77	19	13	DNBR margin for rod bow
18	4/18/77	20	14	Liquid penetrant test of vessel head cladding
19	6/6/77	21	15	Misc.
20	6/30/77	-	-	Page revision issued to correct errors in previous transmittals
21	8/16/77	22	16	SFP rack modification
22	10/11/77	23	17	Revisions to Operating License (SFP rack modification)
23	12/9/77	24	18	Reporting requirements
24	1/18/78	25	19	Misc.
25	2/14/78	26	20	Fire Protection
26	2/27/78	27	21	Revision to Appendix B Tech Specs (Chemical Monitoring & Discharge)
27	3/28/78	28	22	Trip setpoints (negative rate/I.R. high flux)
28	5/18/78	29	23	Issued with Order for Modification of License Dated May 18, 1978 (Power distribution limits)
29	7/18/78	30	24	ECCS Throttle valve surveillance
30	8/25/78	31	25	Inservice inspection of SG tubes

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31	11/1/78	32	26	Remove Part Length RCCAs; RCS P-T Limits; Pressurizer Heatup Rate
32	3/2/79	33	27	Deletion of reactor trip on turbine trip at <5O% power
33	3/14/79	34	28	Incorporate physical Security Plan
34	4/20/79	35	29	First Exxon Reload
35	5/1/79	36	30	Low Pressurizer Pressure SI
36	8/2/79	37	31	NIS Surveillance
-	8/3/79	38	32	RCS Overpressure Protection
-	9/6/79	39	33	Fire Protection; corrections of 8/2/79 and 8/3/79 issued pages
37	11/2/79	40	34	Environmental Tech Specs Special Chlorination Program
38	2/29/80	41	35	ETS Fish Impingement Sampling Blowdown Flow Reporting
39	8/27/80	42	36	ETS Special Chlorination Program
-	8/29/80	-	-	Order Modifying License for EQ
-	9/19/80	-	-	Revised Order Modifying License for EQ
40	10/24/80	-	-	Order Modifying License for EQ Records
41	11/14/80	43	37	Inservice Inspection (ISI) Program
42	12/17/80	44	38	SI Actuation and Power Distribution Limits
43	2/25/81	45	39	Incorporate Safeguards Contingency Plan, Security Force Qualification and Training Plan
44	3/2/81	46	40	TMI Lessons Learned (1/1/80 items)
45	4/1/81	47	41	Minimum Refueling Cavity Water Level and Decay Heat Removal
46	4/20/81	-	-	Order Modifying License for Primary Coolant Isolation Valves
47	5/13/81	48	42	Spent Fuel Storage - Rack Modification (Boraflex)

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NSP Revision (REV) No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
48	7/28/81	49	43	Misc.
49	7/28/81	49	43	Correct Typos in NSP Rev. 48
50	10/28/81	50	44	Snubber Surveillance and Misc.
51	11/13/81	51	45	Secondary Water Chemistry
52	12/4/81	52	46	Reactor and Secondary Coolant Activity
53	12/30/81	53	47	Steam Exclusion Damper Operation, Delete Completed Special Tests, Containment Pressure & Temperature Limits
54	2/26/82	54	48	Delete Environmental in Appendix B
55	3/5/82	55	49	Allowable Airlock Leakage
56	7/16/82	56	50	$BU(E_j)$ Extended to 47 GWD/MTU
57	9/8/82	57	51	EOC Turbine Valve Test Waiver
58	10/18/82	58	52	$BU(E_j)$ Extended to 51 GWD/MTU
59	10/21/82	59	53	Appendix I
60	1/4/83	60	54	IST Program for Pumps and Valves
61	2/2/83	61	55	Misc.: Aux. Feedwater Steam Exclusion, Admin. Changes, and Steam Generator Tube Surveillance
62	2/23/83	62	56	Appendix J Test Program
63	3/23/83	63	57	Containment Ventilation, Event Monitoring Instruments, and Misc.
64	4/6/83	64	58	Overtime
65	9/1/83	65	59	Caustic Standpipe
66	10/3/83	66	60	LOCA Analysis
67	12/28/83	67	61	LOCA Analysis, Rev 1
68	2/21/84	68	62	Chlorine Detection, Hydrogen Recombiners and Misc.
69	3/27/84	69	63	Reactor Coolant Vent System
70	9/12/84	70	64	Post Accident Sampling, Toxic Gas & Misc.

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NSP Revision (REV) No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
71	10/18/84	71	-	Steam Generator Tube Operability (Unit 1)
72	2/15/85	72	65	Cooling Water Header Operability
73	6/25/85	73	66	Reporting Changes, New Table of Contents and Misc.
74	6/26/85	74	67	Removal of Restriction on Use of 266 Spent Fuel Storage Spaces
75	6/26/85	75	68	Shunt Trip Attachment
76	10/11/85	76	69	Authorization to Sleeve Steam Generator Tubes
77	4/3/86	77	70	Change Westinghouse Fuel and Misc.
78	8/28/86	78	71	Inadequate Core Cooling Instrumentation
79	9/23/86	79	72	Extension of Operating Licenses
80	11/14/86	80	73	Heatup/Cooldown Curves and Misc.
81	7/8/87	81	74	Sliding Peaking Factors
82	4/18/88	82	75	Plant Organization and SRO License
83	5/31/88	83	76	High Flux, Power Range (Low Setpoint)
84	9/16/88	84	77	Change to Power Peaking Factors
85	1/5/89	85	78	Security Plan Approval
86	2/7/89	86	79	Reduce Turbine Valve Test Freq.
87	4/3/89	87	80	Eliminate Steam Flow / Feedwater Flow Mismatch Reactor Trip and Low Feedwater Flow Reactor Trip
88	7/25/89	88	81	Transfer of By-Product Material
89	8/28/89	89	82	Heatup/Cooldown Curves and Low Temperature Overpressurization Protection
90	8/28/89	90	83	Increased Fuel Enrichment Limit
91	10/27/89	91	84	LCO Action Statements and Misc.
92	03/13/90	92	85	Delete Cycle Specific Parameters
93	02/11/91	93	86	Reference Approved Methodology

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NSP Revision (REV) No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
94	03/20/91	94	87	Control Rod Operability Limitation
95	04/30/91	95	88	Feedwater Isolation Limitation
96	05/09/91	96	89	Maintenance Procedure Review
97	06/26/91	97	90	Steam Generator Power Operated Relief Valve Action Statement
98	05/08/92	98	91	Snubber Inspection and Test Interval Changes
99	07/09/92	99	92	Single-Failure-Proof Crane Upgrade
100	08/11/92	100	93	4160 V Safeguards Bus Surveillance
101	08/20/92	101	94	Surveillance Requirements Applicability Section
102	09/29/92	102	95	Remove Chlorine Detection
103	12/17/92	103	96	Aux. Electrical and Cooling Water
104	02/05/93	104	97	Monthly Surveillance Testing for ESF Equipment now at IST Frequency
105	05/04/93	105	98	Administrative Changes Related to Organization Operations Committee Membership and Working Hours
106	06/21/93	106	99	Pressurizer PORV
107	07/29/93	107	100	Misc. and Remove Containment Penetration List
108	09/03/93	108	101	Increase Fuel Enrichment Limit
109	12/03/93	109	102	Reference Approved Methodology
110	5/17/94	110	103	Auxiliary Electrical System
111	8/10/94	111	104	Instrumentation tables, etc.
112	9/7/94	112	105	Actions for Core Exit Thermocouple
113	1/5/95	113	106	Emergency Diesel Generator Testing
114	1/11/95	114	107	Radioactive Effluent Report
115	3/8/95	115	108	Frequency of Residual Heat Removal (RHR) System Leakage Testing

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NSP Revision (REV) No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
116	3/10/95	116	109	Reduce Surveillance Testing During Power Operation - Line-Item Tech Spec Improvements from GL 93-05
117	4/18/95	117	110	Appendix J Type A Periodic Retest Schedule
118	5/15/95	118	111	F* Steam Generator Tube Repair Criteria
119	7/3/95	119	112	Control of Airlock Doors During Core Alterations
120	10/6/95	120	113	LCOs for Fire Protection
121	11/9/95	121	114	Post-Accident Monitoring
122	1/24/96	122	115	Radiological Effluent
123	5/21/96	123	116	Pressurizer Safety Valves and Main Steam Safety Valves Lift Setting Tolerance and Safety Limit Curve
124	10/10/96	124	-	Reduce Required Number Of In-Core Detectors thru EOC
125	2/10/97	125	117	Containment Cooling Systems
126	2/19/97	126	118	Appendix J, Option B for Containment Leakage System Tests
127	2/20/97	127	119	Safety Injection Pump Low Temperature Operations
128	3/25/97	128	120	Appendix B License Conditions to Resolve Cooling Water USQ
129	6/12/97	129	121	Credit for Soluble Boron in Spent Fuel Pool Criticality Analysis
129A	6/30/97	Bases	Change	Spent Fuel Pool Personnel Access Doors
130	9/15/97	130	122	Spent Fuel Pool Special Ventilation
131	10/21/97	131	123	Cooling Water System
132	11/4/97	132	124	Incorporate Combustion Engineering Steam Generator Welded Tube Sleeve Designs
133	11/18/97	133	125	Incorporate Voltage-Based Steam Generator Tube Repair Criteria

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NSP Revision (REV) No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
133A	8/26/98	Bases	Change	Allowable Leakage Past Reactor Vessel Head Penetration Seal Weld
134	11/25/97	134	126	Turbine-Driven Auxiliary Feedwater Pump Operability During Startup and Use of Shutdown Auto in Mode 2
135	5/4/98	135	127	Update RCS Heatup/Cooldown Limitations and Incorporate Pressure and Temperature Limits Report (PTLR)
136	7/28/98	136	-	Reduce Required Number of Incore Detectors thru EOC 19
137	8/13/98	137	128	EF* Steam Generator Alternate Repair Criteria
133A	8/26/98	Bases	Change	Allowable Leakage Past Reactor Vessel Head Penetration Seal Welds
138	9/22/98	138	129	Install Diverse Scram Function in AMSAC System
139	10/30/98	139	130	Inoperable Rod Position Indicator Channels
140	11/4/98	140	131	Cooling Water System Emergency Intake Basis
	12/7/98	141	132	Conform Admin Controls Section 6 to Guidance of Standard Tech Specs (Not Distributed, Implement By 9/1/99)
141	12/17/98	142	133	Reactor Coolant Head Vent Surveillance Requirements
142	11/21/98	Bases	Change	Cooling Water Supply to Safeguards Bay
143	3/17/99	143	134	Boric Acid Storage Tank Level Instrumentation
144	4/15/99	144	135	Incorporate Combustion Engineering Topical Report CEN-629-P, “Repair of Westinghouse Series 44 and 51 Steam Generator Tubes Using Leak Tight Sleeves,” Revision 3.

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NSP Revision (REV) No.	Date of Issue	License Amendment No. DPR-42	DPR-60	Remarks
145	4/22/99	Bases	Change	Reactor Core Safety Limits: OTΔT trip locus drops in response to rate of Tave increase (see Safety Evaluation No. 478-14-02.)
146	6/2/99	145	136	License Condition No. 6 Implementation Delay
147	12/7/98	141	132	Conform Chapter 6 to NUREG-1431.
148	8/26/99	146	137	Plant Organizational Structure.
149	12/30/99	Bases Change		Quadrant Power Tilt Ratio limits not applicable below 50% power
150	1/19/00	Bases Change		Pressurizer Heater Capacity
151	2/17/00	147	138	Clarify restrictions on movement of loads within spent fuel pool enclosure
152	2/29/00	148	139	Relocate Design Features to USAR
153	4/19/00	149	140	EF* distance for the steam generator tubes revised by minor correction to calculations
154	2/27/00	Bases Change		Correct references and misc. errors
155	7/11/00	150	141	Fire Protection, revise License Condition 4 SE references
156	7/11/00	151	142	Relocate shutdown margin to COLR
157	7/14/00	152	143	Natural circulation operation
158	8/7/00	153	144	Transfer of operating authority to NMC
159	8/18/00	154	145	License transfer to reflect Xcel merger
160	12/15/00	155	146	One-time amendment to support MCC transfer switch modification

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161	7/11/01	156	147	Boric Acid Reduction: Removed Section 3.2 from Technical Specifications and changed design basis of Safety Injection (SI) to remove Boric Acid Storage Tank as source to SI pump suction.
162	5/30/01	157	148	Amendment approving the use of breakaway ceramic pins to restrain the doors to the auxiliary building special ventilation zone. This amendment changed neither the operating licenses nor the Technical Specifications.
163	2/08/02	– – –	– – –	Issued revised pages to correct administrative errors. Page TS-ii issued with Rev 161 did not reflect the fact the section 3.1.E had been deleted in a previous revision. The last item in paragraph 3.1.A.1.b (3) on Page TS.3.1-1 issued with Rev 157 should have been labeled "(d)", not "(c)".

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164	7/26/02	158	149	Converted Technical Specification Bases to format and guidance of NUREG-1431. NOTE: The Rev No. is not shown on the pages associated with this revision.
165	10/16/02	-	-	Revised TS 3.3.1 Bases to clarify that RTB is OPERABLE when bypassed to restore automatic relay logic to OPERABLE status per TS 3.3.1 Condition O. Made miscellaneous Bases corrections.
166	11/20/02	-	-	Revised TS 3.7.17 Bases to correct references to Figures
167	2/27/03			Revised TS 3.1.7 Bases to clarify that RPIs may be verified to be OPERABLE and clarify that use of moveable incore detectors are not required when Required Action A.2 is entered. Revised TS 3.3.3 Bases to include use of SPDS for Table 3.3.3-1, Item 9. Revised TS 3.4.16 Bases to remove discussion of R-12. Revised TS 3.7.5 Bases to clarify manual valves under administrative control.
168	8/20/03			Revised SR 3.0.1 Bases to clarify testing requirements. Revised Bases for TS 3.6.3, 3.6.5 and 3.6.6 to remove system walkdown requirements. Revised TS 3.7.8 Bases to clarify valve positioning under administrative control. Revised TS 3.7.11 Bases to clarify affect of isolation of components or systems. Corrected typographical errors in Bases for TS 3.5.1, 3.6.3 and 3.7.6.
169	10/3/03	160	151	Revised Bases 3.1.4 and Bases 3.1.7 to allow RPI 1 hour soak time per LA160/151. Revised Bases 3.1.8 to allow use of Dynamic Rod Worth measurement per Bases control program.
170	1/29/04	-	-	Removed “and” from Bases B 3.7.6, revised Bases B 3.7.7 per 50.59 Evaluation 1018, revised Bases B 3.8.1 per TSTF-400.

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171	6/18/04	-	-	Correct Bases B 3.0.6 and add clarification that each steam generator is separate in B 3.3.3.
172	7/2/04	162	153	Incorporate Bases changes associated with transition to Westinghouse safety analysis and includes use of BEACON for core monitoring.
173	6/8/04	163	154	Remove H_2 recombiner and H_2 monitor discussions from Bases.
174	8/27/04	-	-	Revise 3.5.1 discussion of boron build up analyses.
175	9/10/04	166	156	Approved Alternate Source Term (AST) methodology for Fuel Handling Accident and implemented AST by revising TS and Bases B 3.3.5, B 3.9.2 and B 3.9.4.
176	10/27/04	167	157	Revised Bases 3.0, 3.1.3, 3.4.11, 3.4.12, 3.4.13, 3.4.16, 3.4.17, 3.5.3, 3.7.3, 3.7.4, 3.7.5 and 3.8.1 to incorporate LCO 3.0.4 flexibility changes.
177	10/27/04	-	-	Miscellaneous minor corrections to Bases 3.3.3 and 3.4.12.
178	1/27/05	-	-	Revise Bases 3.7.10 to require Air Handler for OPERABILITY and clarify fan test requirements, clarify SR 3.7.5.4 and restore B 3.3.3 discussion of SG Water Level channels
179	7/21/05	-	-	Revise Bases 3.3.7 Applicability to make it consistent with plant design and TS 3.3.7.
180	9/1/05	-	-	Revise Bases 3.8.4 due to revised minimum design battery voltage limit.
181	4/20/06	-	-	Miscellaneous clarifications in Bases 3.1.3, 3.6.5, 3.7.5 and 3.7.8.
182	2/5/06	172	162	Revised Bases due to revised fuel storage curves in TS 3.7.17 and TS 4.3 based on new criticality methodology and analyses.
183	5/24/06	-	-	Revised description of pressurizer heater supplies in SR 3.4.9.3.

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184	6/29/06	173	163	Modified TS Bases 3.6.5 to allow operation with any two containment fan coil units operable during the Completion Time. Revised TS Bases 3.7.8 to incorporate TS 3.6.5 changes.
185	2/2/07	175	165	Clarify required surveillances for installed spare components in TS 3.7.8, TS 3.8.1 and TS 3.9.3.
186	3/21/07	-	-	Revise B 3.5.3 to clarify that only the SI subsystem is required to provide injection. Revise B 3.7.17 criticality analysis reference.
187	3/20/07	177	167	Implement TSTF-449 which revised B 3.4.4 and B 3.4.14, and added new B 3.4.19.
188	5/30/07	178	168	Extend diesel generator Completion Time in TS 3.8.1.
189	6/28/07	179	169	Revised Bases 3.5.1 and 3.6.5 based on use of WCAP-16009 using ASTRUM for Large Break LOCA analyses.
190	8/10/07	180	170	Remove Note from SR 3.1.4.1 and revise Applicability for Bases 3.3.7.
191	10/31/07	181	171	Revise Bases 3.7.2 to relocate closure time to TRM.
192	1/31/08	-	-	Clarify Bases 3.7.13 LCO requirement (e.).
193	1/28/08	183	173	Added LCO Note to TS 3.5.3 to clarify SI pump operability.
194	6/18/08	-	-	Incorporate revised criticality analysis in Bases 3.7.16
195	6/27/08	185	175	Change applicable references from ASME Section XI to ASME OM Code.
196	7/18/08	186	176	Revise heater testing in Bases 3.6.9, 3.7.12 and 3.7.13.
197	8/15/08	187	-	Revised SR 3.8.1.3 to increase the test load for Unit 1 EDGs.
198	10/21/08	189	178	Add power factor requirement to SR 3.8.1.9.

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199	12/17/08	190	179	Revise SR 3.6.5.8 Frequency for CS nozzles.
200	6/19/09	191	180	Revise dose consequences for LOCA and MSLB.
201	7/7/09	192	181	Changes to Allow Use of Westinghouse 0.422-Inch OD 14X14 Vantage+ Fuel.
202	12/1/09	182	172	Revise Bases 3.5.4 to increase RWST level.
203	12/1/09	-	-	Make corrections on page B 3.3.1-27.
204	3/1/10	194	183	Apply SR 3.0.2 interval extension to SR 3.8.1.8.
205	5/20/10	195	184	Modify Bases 3.7.10 for control room envelope habitability requirements.
206	6/21/10	196	185	Revise SR 3.8.1.9 Unit 2 diesel test load description.
207	8/18/10	197	186	Increase power to 1677 MWt by reducing power uncertainty through use of Leading Edge Flow Meter.
208	12/2/10	-	-	Correct negative pressure discussion in SR 3.6.10.2 Bases.
209	4/15/11	-	-	Revise Bases 3.7.16 and 3.7.17 to align with Amendment 7 to ISFSI TS.
210	4/29/11	200	-	Add discussion of SR 3.8.1.10 footnote.
211	5/4/11	201	188	Use of BEACON™ power distribution monitoring system permitted.
212	12/20/11	-	-	Clarify Bases 3.8.4, 3.8.6 and 3.8.7 that the battery chargers are required to be operable when onsite AC power is restored.
213	3/28/12	-	-	Clarify in Bases 3.4.1 that limits may also be from non-DNB limiting accident analyses.
214	3/28/12	-	-	Clarify Bases 3.8.2 that LCO Note only applies to testing both DGs at the same time.
215	1/21/13	-	-	Remove Bases SR 3.7.5.2 discussion of testing on recirculation flow.

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216	5/9/13	207	194	Revise TS Bases 3.7.8 and TS Bases 3.8.3 to require 7-day fuel oil supply for each train to mitigate a design basis accident and separate EDG and DDCLP fuel oil supplies.
217	8/21/13	-	-	Revise TS Bases SR 3.0.2 and SR 3.0.3 to acknowledge EGM 12-001 and RIS 12-10.
218	11/8/13	208	195	Revise TS Bases 3.4.19 to remove Unit 2 original steam generator repair discussion.
219	11/8/13	-	-	Revise TS Bases 3.3.2 to clarify SI – steam line low pressure instrumentation not credited in a harsh environment.
220	12/16/13	206	193	Revise Bases to implement Alternative Source Term.
221	12/16/13	209	196	Revise TS Bases 3.7.16 and 3.7.17 for SFP loading restrictions to meet subcriticality for all postulated conditions.
222	2/5/14	-	-	Correct time to reduce openings in Bases 3.7.12.
223	7/11/14	-	-	Correct steam generator program changes and alternative source term values in Bases 3.4.14, 3.4.17 and 3.7.2.
224	8/14/15	213	201	Revise TS Bases 3.5.3 to reflect removing Note 1 and changing Applicable Mode in TS 3.5.3.
225	8/14/15	214	202	Revise TS Bases 3.8.1 to reflect correction to non-conservative EDG load values in TS 3.8.1.
226	10/8/15	-	-	Revise TS Bases 3.7.8 to clarify operability of CL header and applicability of Condition B when both CL strainers are isolate d or otherwise impaired on a header.
227	1/8/16	-	-	Revise TS Bases 3.2.1 and 3.2.2 to add reference to WCAP-12472-P-A Addendum 1 (BEACON) and to correct typographical error in 3.8.9.
228	1/22/16	-	-	Revise ACTIONS of TS Bases 3.6.3 to clarify use of administrative controls for intermittently unisolating penetration flow paths. Pages B 3.6.3-9 and -10 changed to allow for new text on page B 3.6.3-8.

PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RECORD OF REVISIONS
BASES CHANGES AND LICENSE AMENDMENTS

PI Revision (Rev) No.	Date of Issue	License Amendment No DPR-42	License Amendment No DPR-60	Remarks
229	02/05/16	216	204	Revise TS Bases 3.3.3 to add SG NR level to the discussion of specified functions in TS Table 3.3.3-1.

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

AEC GDC Criterion 6 (Ref. 1) requires that the reactor core shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. This integrity is required during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient.

BASES

BACKGROUND (continued)

Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium-water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Trip System allowable values specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation", in combination with other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude DNB related flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the appropriate operation of the RPS and the steam generator safety valves.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SLs represent a design requirement for establishing the RPS allowable values identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow-Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the USAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The figure provided in the COLR shows the loci of points of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is not less than the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the core exit quality is within the limits defined by the DNBR correlation.

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is,

BASES

SAFETY LIMITS (continued)	it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.
APPLICABILITY	SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves and automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Allowable values for the reactor trip functions are specified in LCO 3.3.1, “Reactor Trip System (RTS) Instrumentation.” In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.
SAFETY LIMIT VIOLATIONS	The following SL violation responses are applicable to the reactor core SLs. If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable. The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits", Criterion 6, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. USAR, Section 14.3.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to AEC GDC Criterion 9, "Reactor Coolant Pressure Boundary," GDC Criterion 33, "Reactor Coolant Pressure Boundary Capability," and GDC Criterion 34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention" (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs).

The design pressure of the RCS is 2485 psig (Ref. 2). During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code. To ensure system integrity, all RCS components were hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there was fuel in the core. Following inception of unit operation, RCS components are pressure tested, in accordance with the requirements of ASME Code, Section XI.

Overpressurization of the RCS could result in a breach of the RCPB, reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 100, "Reactor Site Criteria". If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the pressurizer high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components. The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System, together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The pressurizer high pressure trip is specifically set to provide protection against overpressurization (Ref. 3). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices (Ref. 4).

More specifically, no credit is taken for operation of the following:

a. Pressurizer power operated relief valves (PORVs);

b. Steam generator power operated relief valves;

c. Steam dump system;

d. Rod control system;

e. Pressurizer level control system; or

f. Pressurizer spray valves.

BASES (continued)

SAFETY LIMITS	The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under USAS, Section B31.1 (Ref. 5) is 120% of design pressure. The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2735 psig (Ref. 2).
APPLICABILITY	SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.
SAFETY LIMIT VIOLATIONS	If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour. Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits. The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized. If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL

BASES

SAFETY LIMIT VIOLATIONS (continued)	within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criteria 9, 33 and 34, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. USAR, Section 4.

3. USAR, Section 7.4.

4. USAR, Section 14.4.

5. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may

BASES

LCO 3.0.2 (continued)

be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering LCO 3.0.2 ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits.”

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time other conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the

BASES

LCO 3.0.2 (continued)

Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable resulting in a new LCO not met. In this case, the Completion Times of the new Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

BASES

LCO 3.0.3 (continued)

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with system operations to ensure the stability and availability of the electrical grid. The shutdown shall be initiated so that the time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met;

b. A Condition exists for which the Required Actions have now been performed; or

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then

BASES

LCO 3.0.3 (continued)

the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.15, "Spent Fuel Storage Pool Water Level." LCO 3.7.15 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.15 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.15 of "Suspend movement of irradiated fuel assemblies in the spent fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of

BASES

LCO 3.0.4 (continued)

the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4(b), must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of

BASES

LCO 3.0.4 (continued)

the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

BASES

LCO 3.0.4 (continued)

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., RCS Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

BASES

LCO 3.0.4 (continued)

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective

BASES

LCO 3.0.5 (continued)

maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for supported systems that have a support system LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential

BASES

LCO 3.0.6 (continued)

confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.13, “Safety Function Determination Program (SFDP),” ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

BASES

LCO 3.0.6 (continued)

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCOs 3.1.8 and 3.4.18 allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if

BASES

LCO 3.0.7 (continued)

required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 3.0.8 establishes an exception to LCO 3.0.2 for Technical Specification (TS) supported systems due to an inoperability of a non-Technical Specification (non-TS) support system. The specific non-TS support system for which this exception is allowed is listed in LCO 3.0.8. This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system non-TS Required Actions. The NRC has acknowledged that the system listed in LCO 3.0.8 may be inoperable for the specified Delay Time without entering the TS supported system LCO. If the non-TS support system inoperability is not corrected within the Delay Time, then the TS supported system's Conditions and Required Actions must be entered.

BASES (continued)

LCO 3.0.9

LCO 3.0.9 is provided to clarify the unit applicability of parameters or equipment designations which are specific to one unit.

In the Specifications and Bases, parentheses and footnotes may be used to identify system, component, operating parameter, setpoints, etc. specific to one unit. These are considered an integral part of the LCOs and SRs with which compliance is required for the specified unit.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g. , CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the Test Exception LCO is used as an allowable exception to the

BASES

SR 3.0.1 (continued)

requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performances of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a “once per . . .” interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other

BASES

SR 3.0.2 (continued)

ongoing Surveillance or maintenance activities). As noted in NRC Enforcement Guidance Memorandum 12-001 (Reference 1), the 25 % interval extension allowed by SR 3.0.2 applies to TS Section 5.5 Programs which invoke SR 3.0.2.

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a “once per ” basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

Also, as stated in SR 3.0.2, the 25% extension does not apply to SRs with a specified Frequency of 24 months unless applicability of SR 3.0.2 is specified in the SR Frequency. This is to ensure performance is within equipment performance expectations. This is consistent with present industry analysis that supports refueling cycle intervals up to, but not longer than, 24 months.

BASES

SR 3.0.2 (continued)

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. SR 3.0.3 does not apply to TS 5.5.7, "Inservice Testing Program", tests unless the tests are required by TS Chapter 3 SRs since SR 3.0.3 does not apply to 10CFR 50.55a(f) tests (References 1 through 4). Missed TS 5.5.7 tests not required by a TS Chapter 3 SR should be addressed in the Corrective Action Program (CAP) as a nonconformance to ASME OM requirements.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as

BASES

SR 3.0.3 (continued)

modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed

BASES

SR 3.0.3 (continued)

quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision in included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due

BASES

SR 3.0.4 (continued)

to Surveillance not being met in accordance with LCO 3.0.4. However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

BASES

SR 3.0.4 (continued)

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

REFERENCES

1.) NRC Enforcement Guidance Memorandum (EGM) 12-001, "Dispositioning Noncompliance with Administrative Controls Technical Specifications Programmatic Requirements That Extend Test Frequencies and Allow Performance of Missed Tests".

2.) NRC Regulatory Issue Summary 2012-10, "NRC Staff Position on Applying Surveillance Requirements 3.0.2 and 3.0.3 to Administrative Control Program Tests".

3.) NRC Reply to Industry Questions on EGM 12-001, dated July 6, 2012 (ADAMS Accession Number ML12143A051).

4.) OEE01349900.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to AEC GDC Criteria 27 and 28 (Ref. 1), two independent reactivity control systems must be provided which are capable of holding the reactor core subcritical from any hot standby or hot operating condition. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster control assembly of highest reactivity worth is fully withdrawn and the fuel and moderator temperatures are changed to the nominal hot zero power temperature, 547°F.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Rod Control System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Rod Control System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

BASES

BACKGROUND (continued)	During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on scram. The primary safety analyses that rely on the SDM limits are the boron dilution and main steam line break (MSLB) analyses.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and $\leq$ 200 cal/gm energy deposition for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements, at end of cycle (EOC), is based on a MSLB, as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently an RCS cooldown. This results in a reduction of the reactor coolant

BASES

APPLICABLE SAFETY ANALYSES (continued)

temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As the initial RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. The most limiting MSLB is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a return to power may occur; however, fuel damage as a result of the return to power will not cause offsite doses to exceed the 10 CFR 100 limits.

The most limiting accident at beginning of cycle (BOC) is the boron dilution accident. The required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis, that is, the time available to operators to stop the dilution event. As the unit changes MODES the volume being diluted may change, i.e., if RHR is in service, as well as the critical boron concentration due to the different temperature ranges. Thus different SDMs may be required for the different MODES and dilution flow rates. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration in the RCS.

BASES

LCO (continued)

The COLR provides the shutdown margin requirements. The MSLB and the boron dilution accidents (Ref. 2) are the most limiting analyses that establish the SDM requirements in the COLR. For MSLB accidents, if the LCO is violated, there is a potential to exceed 10 CFR 100, "Reactor Site Criteria," limits. For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with $k_{eff} < 1.0$ and in MODES 3, 4, and 5 the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2 with $k_{eff} \geq 1.0$, the SDM requirements specified in the COLR are ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits."

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components, and the probability of a design basis accident (DBA) occurring during this time is very low. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the operator should borate with the best source available for the plant conditions.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5, the SDM is verified by comparing the RCS boron concentration to a Shutdown Boron Concentration requirement curve that was generated by taking into account:

a. Required SDM;

b. Shutdown and control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration; and

f. Samarium concentration.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the comparison.

REFERENCES

1. AEC “General Design Criteria for Nuclear Power Plant Construction Permits,” Criteria 27 and 28, issued for comment July 10, 1967, as referenced in USAR Section 1.2.
2. USAR, Sections 14.4 and 14.5.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to AEC GDC Criteria 27, 28, 29, and 30 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SHUTDOWN MARGIN (SDM) or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, “SHUTDOWN MARGIN (SDM)”) in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve, which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with

BASES

BACKGROUND (continued)	other variables fixed or stable (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate. In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RATED THERMAL POWER (RTP) and normal operating temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration. When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.
APPLICABLE SAFETY ANALYSES	The acceptance criteria for core reactivity are that the uncertainties in the nuclear design methods are within the expected range and that the calculational models used to generate the safety analyses are adequate. Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are

BASES

APPLICABLE SAFETY ANALYSES (continued)

very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions early in the cycle (≤ 60 effective full power days (EFPD)) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists early in the cycle, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed early in the cycle, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the nuclear design methods are larger than expected. A limit on the reactivity balance of $\pm$ 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron

BASES

APPLICABILITY (continued)	Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. Verification of measured core reactivity (SR 3.1.2.1) is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If

BASES

ACTIONS

A.1 and A.2 (continued)

operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity must be verified following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling). The comparison is made when the core conditions such as control rod position, moderator temperature, and samarium concentration are fixed or stable. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at beginning of cycle (BOC).

SR 3.1.2.2

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made,

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.2 (continued)

considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The required Frequency of 31 effective full power days (EFPD) is acceptable based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly. The SR is modified by two Notes. Note 1 states that the SR is only required to be performed after 60 EFPD. Note 2 indicates that the normalization of predicted core reactivity to the measured value may take place within the first 60 EFPD after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criteria 27, 28, 29 and 30, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. USAR, Section 14.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Isothermal Temperature Coefficient (ITC)

BASES

BACKGROUND

According to AEC GDC Criterion 8 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The moderator temperature coefficient (MTC) relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The ITC is defined as the reactivity change associated with a unit change in the moderator and fuel temperatures. Essentially, the ITC is the sum of the MTC and fuel temperature coefficient. The ITC is measured directly during low power PHYSICS TESTS in order to verify analytical prediction of the MTC. The units of the isothermal temperature coefficient are pcm/°F, where 1 pcm = 1E-5 $\Delta k/k$.

The reactor is designed to operate with a negative ITC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements at beginning of cycle (BOC). Reactor cores are designed so that the BOC ITC is less than zero when THERMAL POWER is at RTP. The actual value of the ITC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed

BASES

BACKGROUND (continued)

distributed poisons to yield an ITC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles are evaluated to ensure that the ITC does not exceed the limits.

The limitations on ITC in Limiting Condition for Operation (LCO) 3.1.3 ensure that the core is inherently stable during power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the reactor coolant system will compensate for any unintended reactivity increases.

The limitations on ITC contained in the Core Operating Limits Report (COLR) are provided to ensure that the value of MTC remains within the limiting conditions assumed in the USAR accident and transient analyses.

The operational upper limit of ITC (as specified in Condition A) is the upper limit specified in the COLR since this value will always be less than or equal to the maximum upper limit specified in the LCO.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified ITC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The ITC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The USAR (Ref. 2) contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions for the cycle exposure

BASES

APPLICABLE SAFETY ANALYSES (continued)

being evaluated to ensure that the accident results are bounding.

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive (i.e., upper limit). Such accidents include the rod withdrawal transient from either zero or RTP, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include the main steam line break.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOC or EOC life. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, ITC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the ITC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values will remain within the bounds of the original accident analyses during operation.

Assumptions made in safety analyses require that the ITC be less positive than a given upper bound and more positive than a given lower bound. The ITC is most positive at BOC; this upper bound must not be exceeded. This maximum upper limit usually occurs at BOC, all rods out (ARO), hot zero power conditions. At EOC the ITC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

BASES

LCO (continued)

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance check at BOC on ITC provides confirmation that the ITC is behaving as anticipated and will be within limits at 70% RTP, full power, and EOC so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOC positive limit and the EOC negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

If the LCO limits are not met, the assumptions of the safety analysis may not be met. The core could violate criteria that prohibit a return to criticality, or the DNBR criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

APPLICABILITY

Technical Specifications place both LCO and SR values on ITC, based on the safety analysis assumptions described above.

In MODE 1, the limits on ITC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup accidents (such as the uncontrolled rod cluster control assembly withdrawal) will not violate the assumptions of the accident analysis. The lower ITC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents at EOC will not violate the assumptions of the accident analysis since ITC becomes more negative as the cycle burnup increases and the RCS boron concentration is reduced. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

BASES (continued)

ACTIONS

A.1

ITC must be kept within the upper limit specified in LCO 3.1.3 to ensure that assumptions made in the safety analysis remain valid. The upper limit of Condition A is the upper limit specified in the COLR since this value will always be less than or equal to the maximum upper limit specified in the LCO.

If the upper ITC limit is violated at BOC, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits in the future. The ITC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the ITC measurement and computing the required bank withdrawal limits.

The control rods are maintained within the administrative withdrawal limits until a subsequent calculation verifies that ITC has been restored within its limit. As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the ITC to become more negative. Using physics calculations, the time in cycle life at which the calculated ITC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1

Exceeding the EOC ITC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If it is determined during PHYSICS TESTS that the EOC ITC value will exceed the most negative ITC limit specified in the COLR, the safety analysis and core design must be re-evaluated prior to reaching the equivalent of an equilibrium RTP ARO boron concentration of 300 ppm to ensure that operation near the EOC remains acceptable. The 300 ppm limit is sufficient to prevent EOC operation at or below the accident analysis MTC assumptions.

Condition C has been modified by a Note that requires Required Action C.1 to be completed whenever this Condition is entered. This is necessary to ensure that the plant does not operate at conditions where the ITC would be below the most negative limit specified in the COLR.

Required Action C.1 is modified by a Note which states that LCO 3.0.4.c is applicable. This Note is provided since the requirement to re-evaluate the core design and safety analysis prior to reaching an equivalent RTP ARO boron concentration of 300 ppm is adequate action without restricting entry into MODE 1.

D.1

If the re-evaluation of the safety analysis cannot support the predicted EOC ITC lower limit, or if the Required Actions of Condition C are not completed within the associated Completion Time the plant must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to MODE 4 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the ITC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most positive ITC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOC ITC value for ARO will be obtained from measurements during the PHYSICS TESTS after refueling. The ARO value can be directly compared to the BOC ITC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

Measurement of the ITC at the beginning of the fuel cycle is adequate to confirm that the ITC remains within its upper limit.

SR 3.1.3.2

This SR requires measurement of ITC at BOC prior to exceeding 70% RTP after each refueling in order to confirm compliance with the 70% RTP ITC limit in the COLR. The Frequency of “Once after each refueling prior to THERMAL POWER exceeding 70% RTP” ensures the limit will be met prior to being applicable.

SR 3.1.3.3

This SR requires measurement of ITC at BOC prior to exceeding 70% RTP after each refueling in order to confirm compliance with the most negative ITC LCO. Meeting this limit prior to exceeding 70% RTP ensures that the limit will also be met at EOC.

The ITC value for EOC is derived from the ITC low power PHYSICS TESTS. The EOC value is calculated using the predicted EOC ITC from the core design report and the difference between the

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.1.3.3</u> (continued) measured and predicted BOC ITC. The predicted EOC value is directly compared to the most negative EOC value established in the COLR to ensure that the predicted EOC negative MTC value is within the safety analysis assumptions.
REFERENCES	1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 8, issued for comment July 10, 1967, as referenced in USAR Section 1.2. 2. USAR, Sections 14.4 and 14.5.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are AEC GDC Criteria 6, 14, 27, and 28 (Ref. 1), and 10 CFR 50.46 (Ref. 2).

Mechanical or electrical failures may cause a control or shutdown rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately ⅝ inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

BASES

BACKGROUND (continued)

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. Both units have four control banks and two shutdown banks.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is approximately halfway withdrawn. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent indications, which are the bank demand position indication (usually the group step counters) and the individual Rod Position Indication (RPI) System.

The bank demand position indication counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The bank

BASES

BACKGROUND (continued)

demand position indication is considered highly precise (± 1 step or ± ⅝ inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides a highly reliable indication of rod position, but at a lower accuracy than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. The RPI System is designed with an accuracy of ± 5% (approximately 12 steps) of full rod travel. There are inaccuracies arising from the normal range of coolant temperature variation from hot shutdown to full power which are compensated for by allowing ± 24 steps at the lower and upper ends of rod travel.

With an indicated deviation of 12 steps between the group step counter and RPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches. At the lower and upper ends of rod travel with an indicated deviation of 24 steps between the group step counter and RPI, the deviation between actual rod position and the demand position could be 36 steps, or 22.5 inches.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment assure that:

a. There are no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment. With control banks at their insertion limits or all rods out, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on DNBR in both these cases bounds the situation when a rod is misaligned from its group by 24 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA fully withdrawn (Ref. 3).

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected, that the linear heat rates (LHRs) are not significantly affected, or that THERMAL POWER will be adjusted so that excessive local LHRs will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F_{\Delta H}^{N}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned the assumed power distribution used in the safety analysis may not be preserved.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by core power distribution measurements. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on control rod OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The control rod OPERABILITY requirements (i.e., trippability) are separate from the alignment requirements which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. The rod OPERABILITY requirement is satisfied provided the rod will fully insert in the required rod drop time assumed in the safety analysis. Rod control malfunctions that result in the inability to move a rod (e.g., rod lift coil failures), but that do not impact trippability, do not result in rod inoperability.

The rod alignment requirements are satisfied when individual actual rod positions are within 24 steps of their group step counter demand position when the demand position is between 30 and 215 steps, or within 36 steps of their group step counter demand position when the demand position is $\leq$ 30 steps, or $\geq$ 215 steps.

BASES

LCO (continued)	The requirement to maintain the rod alignment to within plus or minus 12 steps when the group step counter demand position is between 30 and 215 steps is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed. Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis. This LCO is modified by a Note indicating individual control rod position indications may not be within limits for up to and including one hour following substantial control rod movement. This allows up to one hour of thermal soak time to allow the control rod drive shaft to reach thermal equilibrium and thus present a consistent position indication. Substantial rod movement is considered to be 10 or more steps in one direction in less than or equal to one hour. In accordance with this Note, the comparison of bank demand position and RPI may take place at any time up to one hour after rod motion, at any power level. Based on this allowance, rod position may be considered within limits during the thermal soak time to allow position indication to stabilize.
APPLICABILITY	The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are normally bottomed and the reactor is shutdown and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required

BASES

APPLICABILITY (continued)

SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (i.e., untrippable), there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating boration and restoring SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

B.1.1 and B.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 15 steps from the top of the core would require a significant power reduction, since control bank D must be moved fully in and control bank C must be moved in to approximately 100 to 115 steps.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour.

The Completion Time of 1 hour represents the time necessary for determining the unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.1.1, B.2.1.2, B.2.2, B.3, and B.4

For continued operation with a misaligned rod, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$ must be verified within limits or the high neutron flux trip setpoint must be reduced, SDM must periodically be verified within limits, the safety analyses must be re-evaluated to confirm continued operation is permissible, and, if necessary, the power level must be reduced to a level consistent with the safety analysis. Considerations in these analyses include the potential ejected rod worth and associated transient power distribution peaking factors. The analysis shall include due allowance for nonuniform fuel depletion in the neighborhood of the inoperable rod.

BASES

ACTIONS

B.2.1.1, B.2.1.2, B.2.2, B.3, and B4 (continued)

Verifying that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within the required limits (i.e., SR 3.2.1.1, SR 3.2.1.2 and SR 3.2.2.1) ensures that current operation at RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 8 hours allows sufficient time to obtain core power distribution measurements using either the incore flux mapping system or the Power Distribution Monitoring System and to calculate $F_Q(Z)$ and $F_{\Delta H}^N$.

In lieu of determining hot channel factors ($F_Q(Z)$ and $F_{\Delta H}^N$) within the Completion Time of 8 hours, reducing the high neutron flux trip setpoint to 85% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded. The Completion Time of 8 hours gives the operator sufficient time to accomplish an orderly power reduction and setpoint change without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analyses to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. The accident analyses presented in Ref. 3 that may be adversely affected will be evaluated to ensure that the analysis results remain valid for the duration of continued operation under these conditions.

If the analyses do not support continued operation at RTP, then the power must be reduced to a level consistent with the safety analyses.

BASES

ACTIONS

B.2.1.1, B.2.1.2, B.2.2, B.3, and B4 (continued)

A Completion Time of 30 days is sufficient time to obtain the required input data and to perform the analysis and adjust power level.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which eliminates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases for LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and initiate boration. Boration will continue until the required SDM is restored.

BASES

ACTIONS (continued)

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. The unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by ≥ 10 steps will not cause radial or axial power tilts, or oscillations, to occur providing rod alignment limits are not exceeded. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.3 (continued)

the average moderator temperature $\geq$ 500°F to simulate a reactor trip under actual conditions. Actual rod drop time is measured from opening of the reactor trip breaker (RTB) which is conservative with respect to beginning of decay of stationary gripper coil voltage.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits" Criteria 6, 14, 27, and 28, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants".

3. USAR, Section 14.4.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods define the deepest insertion into the core with respect to core power which is allowed and are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SHUTDOWN MARGIN (SDM) and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are AEC GDC Criteria 27, 28, 29, and 32 (Ref. 1), and 10 CFR 50.46 (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution, reactivity limits, and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Some banks may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs that consists of two groups are moved in a staggered fashion, but always within one step of each other. Each reactor has four control banks and two shutdown banks. See LCO 3.1.4, “Rod Group Alignment Limits,” for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, “Rod Position Indication,” for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks

BASES

BACKGROUND (continued)

must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero

BASES

APPLICABLE SAFETY ANALYSES (continued)

power (547°F), and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown and control rod bank insertion limits assure that:

a. There are no violations of:

   1. specified acceptable fuel design limits, or

   2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits assures that the maximum linear heat generation rate or peaking factor will be less than that used in the misaligned rod analysis. Operation at the insertion limit also assures that the maximum ejected RCCA worth will be less than the limiting value used in the ejected RCCA analysis.

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

The LCO is modified by a Note indicating that a shutdown bank may be below the insertion limit when required for performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. In MODES 3, 4, 5, or 6, the shutdown bank insertion limit does not apply because the reactor is not producing fission power. In shutdown MODES the OPERABILITY of the shutdown rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, “Boron Concentration,” ensures adequate SDM in MODE 6.

ACTIONS

A.1.1, A.1.2 and A.2

With one or more shutdown banks not within insertion limits verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

BASES

ACTIONS

A.1.1, A.1.2 and A.2 (continued)

Operation beyond the LCO limits is allowed for a short time period in order to take appropriate action because the simultaneous occurrence of either an accident or transient during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability. The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If Required Actions A.1 and A.2 cannot be completed within the associated Completion Times, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of 12 hours is adequate to ensure that they are within their insertion limits. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits" Criteria 27, 28, 29, and 32, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

3. USAR, Sections 14.4 and 14.5.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods define the deepest insertion into the core with respect to core power which is allowed and are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SHUTDOWN MARGIN (SDM), and initial reactivity insertion rate. The control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

The applicable criteria for these reactivity and power distribution design requirements are AEC GDC 27, 28, 29, and 32 (Ref. 1), and 10 CFR 50.46 (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation ($k_{eff} \geq 1.0$) to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Some banks may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs that consists of two groups are moved in a staggered fashion, but always within one step of each other. Each reactor has four control banks and two shutdown banks. See LCO 3.1.4, “Rod Group Alignment Limits,” for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, “Rod Position Indication,” for position indication requirements.

BASES

BACKGROUND (continued)

Insertion Limits

The control bank insertion limits are specified in a figure in the COLR. The control banks are required to be at or above the insertion limit lines.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations. The fully withdrawn position is defined in the COLR. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature.

Overlap and Sequence

The insertion limits figure in the COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance traveled together by two control banks. By overlapping control bank movements, the small reactivity addition at the beginning and end of control bank travel will be compensated for; that is, the overlapping sequential movement of control banks makes the reactivity addition more uniform.

Control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the fully withdrawn position, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B,

BASES

BACKGROUND

Overlap and Sequence (continued)

and C are at the fully withdrawn position, and control bank D is near the fully withdrawn position at RTP. The insertion sequence is the opposite of the withdrawal sequence (i.e., bank D is inserted first) but follows the same overlap pattern. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

General

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits assures fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant will be bounded by the safety analysis results in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other transient requiring termination by a Reactor Trip System (RTS) trip function.

BASES (continued)

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power (547°F), and to maintain the required SDM at rated no load temperature (Ref. 3). The control bank insertion limit also limits the reactivity worth of an ejected control rod.

The acceptance criteria for addressing shutdown and control bank insertion limits assure that:

a. There are no violations of:

    1. specified acceptable fuel design limits, or

    2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Operation at the insertion limits assures that the maximum linear heat generation rate or peaking factor will be less than that used in the misaligned rod analysis. Operation at the insertion limit also assures that the maximum ejected RCCA worth will be less than the limiting value used in the ejected RCCA analysis.

The control bank insertion, sequence and overlap limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is limited, and ensuring adequate negative reactivity insertion is available on a trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

The LCO is modified by a Note indicating that a control bank may be below the insertion limit when required for performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would normally violate the LCO.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, and SDM. Applicability in MODE 2 with $k_{eff} < 1.0$, and in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

BASES (continued)

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 is normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"). If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either an accident or transient during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlap limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

BASES

ACTIONS (continued)

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 2 with $k_{eff} < 1.0$, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
SURVEILLANCE

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits. Prior to achieving criticality, the estimated critical position calculation appropriate for the time at which criticality is achieved shall be verified for control bank position.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. Typically, a series of ECPs are prepared in time increments applicable for a series of criticality times before and after the estimated time for achieving criticality. These ECPs account for the various factors which affect the ECP, including xenon concentration changes. The operators use the ECP applicable for the time the reactor actually achieves criticality.

SR 3.1.6.2

Verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

BASES

SURVEILLANCE (continued)

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits" Criteria 27, 28, 29, and 32, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors".

3. USAR, Sections 14.4 and 14.5.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to AEC GDC Criteria 12 and 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SHUTDOWN MARGIN (SDM). Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of

BASES

BACKGROUND (continued)

the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

The axial positions of shutdown rods and control rods are determined by two separate and independent systems: the bank demand position indication (commonly called group step counters) and the individual Rod Position Indication (RPI) System.

The bank demand position indication counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The bank demand position indication is considered highly precise ($\pm$ 1 step or $\pm$ ⅝ inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides a highly reliable indication of actual control rod position, but at a lower accuracy than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. The RPI System is designed with an accuracy of $\pm$ 5 % (approximately 12 steps) of full rod travel. There are inaccuracies arising from the normal range of coolant temperature variation from hot shutdown to full power which are compensated for by allowing $\pm$ 24 steps at the lower and upper ends of rod travel. With an indicated deviation of 12 steps between the group step counter and RPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches. At the lower and upper ends of rod travel with an indicated deviation of 24 steps between the group counter and RPI, the deviation between actual rod position and the demand position could be 36 steps, or 22.5 inches.

BASES (continued)

APPLICABLE SAFETY ANALYSES	Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions. The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident.
LCO	LCO 3.1.7 specifies that the RPI System and bank demand position indication be OPERABLE for each control rod. For the control rod position indicators to be OPERABLE requires the following: a. The RPI System indicates within 12 steps of the group step counter demand position when the demand position is between 30 and 215 steps, or within 24 steps of their group step counter demand position when the demand position is greater than or equal to 215 steps, or less than or equal to 30 steps, or individual rod position indication has been verified to be in agreement with actual rod position through independent means such as movable incore detectors or the Power Distribution Monitoring System in response to Required Actions; and

BASES

LCO
(continued)

b. Bank demand indication has been calibrated either in the fully inserted position or to the RPI System. Demand position indication may be provided by various means such as step counters, Emergency Response Computer System (ERCS), calculations using rod drive cabinet counters or Pulse to Analog counters.

The 12 step agreement limit between bank demand position indication and the RPI System when the demand position is between 30 and 215 steps indicates that the bank demand position indication is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given above, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

BASES

LCO
(continued)

This LCO is modified by a Note indicating individual control rod position indications may not be within limits for up to and including one hour following substantial control rod movement. This allows up to one hour of thermal soak time to allow the control rod drive shaft to reach thermal equilibrium and thus present a consistent position indication. Substantial rod movement is considered to be 10 or more steps in one direction in less than or equal to one hour.

In accordance with this Note, this comparison of bank demand position and RPI may take place at any time up to one hour after rod motion, at any power level. Based on this allowance, position indication may be considered OPERABLE during the thermal soak time to allow position indication to stabilize.

APPLICABILITY

The requirements on the RPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System. See LCO 3.1.1, “SHUTDOWN MARGIN (SDM),” for SDM requirements in MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5 and LCO 3.9.1, “Boron Concentration,” for boron concentration requirements during MODE 6.

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable RPI and each demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

A.1

When one RPI channel per group fails, the position of the rod may still be determined indirectly by core power distribution measurement using either the movable incore detectors or the Power Distribution Monitoring System. Based on experience, normal power operation does not require excessive movement of banks. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. Verification may determine that the RPI is OPERABLE and the rod is misaligned, then the Conditions of LCO 3.1.4, “Rod Group Alignment Limits” must be entered.

A.2

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

BASES

ACTIONS

A.2 (continued)

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1, B.2, B.3, and B.4

When more than one RPI channel per group fails, additional monitoring shall be performed to assure that the reactor remains in a safe condition. The demand position from the group step counters associated with the rods with inoperable position indicators shall be monitored and recorded on an hourly basis. This ensures a periodic assessment of rod position to determine if rod movement in excess of 24 steps has occurred since the last determination of rod position. If rod movement in excess of 24 steps has occurred since the last determination of rod position, the Required Action of B.3 is required.

The reactor coolant system average temperature shall be monitored and recorded on an hourly basis. Monitoring and recording of the reactor coolant system average temperature may provide early detection of mispositioned or dropped rods.

If THERMAL POWER has not been reduced ≤ 50% RTP in accordance with Required Action A.2 and one or more rods have been moved in excess of 24 steps in one direction, since the position was last determined via Required Action A.1, then action is initiated sooner in accordance with Required Action B.3 to begin verifying that these rods are still properly positioned relative to their group positions. The 4 hour allowance for completion of this action allows adequate time to complete the rod position verification using either the movable incore detectors or the Power Distribution Monitoring System.

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

The position of rods with inoperable RPIs will also continue to be verified indirectly using either the movable incore detectors or the Power Distribution Monitoring System (PDMS) every 8 hours in accordance with Required Action A.1 if THERMAL POWER has not been reduced ≤ 50% RTP in accordance with Required Action A.2. Using the movable incore detectors or the PDMS provides further assurance that the rods have not moved.

Based on experience, normal power operation does not require excessive movement of banks. Therefore, the actions specified in this condition are adequate for continued full plant operation for up to 24 hours since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour allowed out of service time also provides sufficient time to troubleshoot and restore the RPI System to operation following a component failure in the system, while avoiding the challenges associated with a plant shutdown.

C.1.1 and C.1.2

Demand position indication is provided by any of the following means: step counters; ERCS; calculations using rod drive cabinet counters and Pulse to Analog counters. With all indication for one demand position per bank inoperable, the rod positions can be determined by the RPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the rod position indication of the most withdrawn rod and the rod position indication of the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate. This ensures that the most withdrawn and least withdrawn rod are no more than 24 steps apart (including instrument

BASES

ACTIONS

C.1.1 and C.1.2 (continued)

uncertainty) which bounds the accident analysis assumptions. This verification can be an examination of logs, administrative controls, or other information that shows that all RPIs in the affected bank are OPERABLE.

C.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the RPI agrees with the demand position within 12 steps (between 30 and 215 steps) or within 24 steps (when ≤ 30 steps or ≥ 215 steps) ensures that the RPI is operating correctly.

This Surveillance is performed prior to reactor criticality after each removal of the reactor head as there is the potential for unnecessary plant transients if the SR were performed with the reactor at power.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits" Criteria 12 and 13, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. USAR, Sections 14.4 and 14.5.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions-MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B, requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant.

The key objectives of a test program are to:

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power, and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed (Ref. 1).

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS required for reload fuel cycles (Ref. 1) in MODE 2 are listed below:

a. Critical Boron Concentration-Control Rods Withdrawn;

b. Critical Boron Concentration-Control Rods Inserted (not required for dynamic rod worth measurement);

c. Control Rod Worth; and

d. Isothermal Temperature Coefficient (ITC).

Low power PHYSICS TESTS may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration-Control Rods Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With all rods out, bank D is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test could violate LCO 3.1.3, “Isothermal Temperature Coefficient (ITC).”

b. The Critical Boron Concentration-Control Rods Inserted Test measures the critical boron concentration at HZP, with the highest worth rod bank fully inserted into the core. This test is used to give an indication of the boron reactivity coefficient.

BASES

BACKGROUND (continued)

With the core at HZP and all banks fully withdrawn, the boron concentration of the reactor coolant is gradually lowered. The selected bank is then inserted to make up for the decreasing boron concentration until the selected bank has been moved over its entire range of travel. The reactivity resulting from each incremental bank movement is measured with a reactivity computer. The difference between the measured critical boron concentration with all rods fully withdrawn and with the bank inserted gives an indication of the Boron Reactivity Coefficient compared to the measured bank worth. Performance of this test could violate LCO 3.1.4, “Rod Group Alignment Limits”; LCO 3.1.5, “Shutdown Bank Insertion Limit”; or LCO 3.1.6, “Control Bank Insertion Limits.”

c. The Control Rod Worth Test is used to measure the reactivity worth of selected control banks. This test is performed at HZP and has four alternative methods of performance. The first method, the Boron Dilution Method, varies the reactor coolant boron concentration and moves the selected control bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining control banks. The second method, the Rod Swap Method, measures the worth of a predetermined reference bank using the Boron Dilution Method above. The reference bank is then nearly fully inserted into the core. The selected bank is then inserted into the core as the reference bank is withdrawn. The HZP critical conditions are then determined with the selected bank fully inserted into the core. The worth of the selected bank is inferred, based on the position of the reference bank with respect to the selected bank. This sequence is repeated as necessary for the remaining control banks. The third method, the Boron Endpoint Method, moves the selected control bank over its entire length of travel and then varies the reactor coolant boron concentration to achieve HZP criticality again. The difference in boron concentration is the worth of the

BASES

BACKGROUND (continued)

selected control bank. This sequence is repeated for the remaining control banks. The fourth method, Dynamic Rod Worth Measurement (DRWM), measures each bank worth by inserting rods continuously into the core at their maximum speed. The banks are inserted one at a time while the reactivity change is measured with a reactivity computer. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

d. The ITC Test measures the ITC of the reactor. This test is performed at HZP using the Slope Method. The Slope Method varies RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The ITC at beginning of cycle (BOC), 70% RTP and at end of cycle (EOC) is determined from the ITC measured in this test. This test satisfies the requirements of SR 3.1.3.1, SR 3.1.3.2 and SR 3.1.3.3. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The above mentioned PHYSICS TESTS may require the operating control or process variables to deviate from their LCO limitations.

The USAR defines requirements for initial testing of the facility, including PHYSICS TESTS. USAR Appendix J summarizes the initial plant startup, zero, low power, and power tests. Requirements for reload fuel cycle PHYSICS TESTS are defined in Reference 1. Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design

BASES

APPLICABLE SAFETY ANALYSES (continued)	criteria are not violated. The requirements specified in the following LCOs may be suspended for PHYSICS TESTING: LCO 3.1.3, "Isothermal Temperature Coefficient (ITC)"; LCO 3.1.4, "Rod Group Alignment Limits"; LCO 3.1.5, "Shutdown Bank Insertion Limits"; LCO 3.1.6, "Control Bank Insertion Limits"; and LCO 3.4.2, "RCS Minimum Temperature for Criticality". When these LCOs are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 535°F, and SDM is within the limits provided in the COLR. The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exception LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	This LCO allows the reactor parameters of ITC and minimum temperature for criticality to be outside their specified limits to conduct PHYSICS TESTS in MODE 2, to verify certain core physics parameters. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. One Power Range Neutron Flux channel may be bypassed, reducing the number of required channels from "4" to "3". Operation beyond specified limits is permitted for the purpose

BASES

LCO (continued)

of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3, 6, and 16.e, may be reduced to "3" required channels during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is $\geq$ 535°F;

b. SDM is within the limits provided in the COLR; and

c. THERMAL POWER is $\leq$ 5% RTP.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability is stated as "during PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RTP maximum power level is not exceeded. Should the THERMAL POWER exceed 5% RTP, and consequently the unit enter MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification within 1 hour.

BASES

ACTIONS (continued)

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest T_{avg} is < 535°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 535°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If Required Action C.1 cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL OPERATIONAL

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1 (continued)

TEST is performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is $\geq$ 535°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.3

Verification that the THERMAL POWER is $\leq$ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of the THERMAL POWER at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.4

Prior to achieving criticality, the SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.4 (continued)

b. Control and shutdown bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration; and

f. Samarium concentration.

After achieving criticality, this SR is met by determining the reactivity insertion available from tripping the shutdown and control banks.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

REFERENCES

1. ANSI/ANS-19.6.1-1985, “Reload Startup Physics Tests for Pressurized Water Reactors.”

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using either the incore detector system or the Power Distribution Monitoring System. These measurements are generally taken with the core at or near equilibrium conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents an equilibrium condition, it does not include the variations in the values of $F_Q(Z)$ which are present during non-equilibrium situations such as load following or power ascension.

BASES

BACKGROUND (continued)	To account for these possible variations, the equilibrium value of $F_Q(Z)$ is adjusted as $F_Q^W(Z)$ by an elevation dependent factor that accounts for the calculated worst case transient conditions. Core monitoring and control under non-equilibrium conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During transient conditions arising from events of moderate frequency (Condition II events), there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition (Ref. 1);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 1); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 2).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Large Break LOCA (LBLOCA) analysis is the analysis that determines the LCO limit for $F_Q(Z)$. The $F_Q(Z)$ assumed in the Safety Analysis for other postulated accidents is either equal to or greater than that assumed in the LBLOCA analysis. Therefore, this LCO provides conservative limits for other postulated accidents. $F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \leq \frac{CFQ}{P} \quad K(Z) \quad \text{for } P > 0.5$$

$$F_Q(Z) \leq \frac{CFQ}{0.5} \quad K(Z) \quad \text{for } P \leq 0.5$$

where: CFQ is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

For Relaxed Axial Offset Control operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

BASES

LCO
(continued)

An $F_Q^C(Z)$ evaluation requires obtaining a power distribution measurement in MODE 1 from which a measured value ($F_Q^M(Z)$) of $F_Q(Z)$ is obtained. If the power distribution measurement is obtained with the movable incore detector system,

$$F_Q^C(Z) = F_Q^M(Z)*(1.0815)$$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances (1.03) multiplied by a factor associated with the flux map measurement uncertainty (1.05) (Ref. 3, 5, and 6).

If the power distribution measurement is obtained with the Power Distribution Monitoring System,

$$F_Q^C(Z) = F_Q^M(Z)*(1.03)(1.0 + \frac{U_Q}{100})$$

where 1.03 is a factor that accounts for fuel manufacturing tolerances and U_Q is a factor that accounts for Power Distribution Monitoring System measurement uncertainty (%), determined as described in Reference 5.

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the power distribution measurement was taken.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z)\ W(Z)$$

where W(Z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation. W(Z) is included in the COLR. The $F_Q^W(Z)$ is calculated at equilibrium conditions.

BASES

LCO (continued)

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

This LCO precludes core power distributions that could violate the assumptions in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q^C(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required, and if $F_Q^W(Z)$ cannot be maintained within the LCO limits, reduction of the AFD limits is required. Note that sufficient reduction of the AFD limits will also result in a reduction of the core power.

Violating the LCO limits for $F_Q(Z)$ may result in unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by $\geq$ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by factors accounting for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is

BASES

ACTIONS

A.1 (continued)

the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require power reductions within 15 minutes of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux-High trip setpoints by $\geq$ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux-High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux-High trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux-High trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux-High trip setpoints.

BASES

ACTIONS (continued)

A.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Overpower ΔT setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Overpower ΔT trip setpoints.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels, and future operations, are consistent with safety analyses assumptions.

BASES

ACTIONS

A.4 (continued)

Condition A is modified by a Note that requires Required Action A.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1, even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD limits by $\geq$ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, maintains an acceptable absolute power density such that even if a transient occurred, core peaking factors are not exceeded (Ref. 4).

The percent that $F_Q(Z)$ exceeds its transient limit is calculated based on the following expression:

$$\left\{\left(\begin{array}{l}\text{maximum}\\ \text{over z}\end{array}\left[\frac{F_Q^C(Z) * W(z)}{\frac{CFQ}{P} * K(z)}\right]\right) - 1\right\} * 100 \text{ for } P > 0.5$$

BASES

ACTIONS

B.1 (continued)

$$\left\{\left(\begin{array}{l}\text{maximum}\\ \text{over z}\end{array}\left[\frac{F_Q^C(Z) * W(z)}{\frac{CFQ}{0.5} * K(z)}\right]\right) - 1\right\} * 100 \text{ for } P \le 0.5$$

The implicit assumption is that if W(Z) values were recalculated (consistent with the reduced AFD limits), then $F_Q^C(Z)$ times the recalculated W(Z) values would meet the $F_Q(Z)$ limit. Note that complying with this action (of reducing AFD limits) may also result in a power reduction. Hence the need for B.2, B.3 and B.4.

B.2

A reduction of the Power Range Neutron Flux-High trip setpoints by $\geq$ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

BASES

ACTIONS (continued)

B.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

B.4

Verification that $F_Q^W(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action B.1, ensures that core conditions during operation at higher power levels, and future operation, are consistent with safety analyses assumptions.

Condition B is modified by a Note that requires Required Action B.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action B.1, even when Condition B is exited prior to performing Required Action B.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

BASES

ACTIONS (continued)

C.1

If Required Actions A.1 through A.4 or B.1 through B.4 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F^C_Q(Z)$ and $F^W_Q(Z)$ are within their specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F^C_Q(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of $F^C_Q(Z)$ before exceeding 75% RTP. This ensures that some determination of $F_Q(Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F^C_Q(Z)$ and $F^W_Q(Z)$ following a power increase of more than 10%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F^C_Q(Z)$ and $F^W_Q(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

SR 3.2.1.1

Verification that $F^C_Q(Z)$ is within its specified limits involves increasing $F^M_Q(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F^C_Q(Z)$ as described in the preceding LCO section. $F^C_Q(Z)$ is then compared to its specified limits. The limit with which $F^C_Q(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F^C_Q(Z)$ limit is met during the power ascension following a refueling, including when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by $\geq$ 10% RTP since the last determination of $F^C_Q(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F^C_Q(Z)$ values are being reduced sufficiently with the power increase to stay within the LCO limits).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

The Frequency of 31 effective full power days (EFPD) is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because power distribution measurements are taken at or near steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the measurements. These variations are, however, conservatively calculated during the nuclear design process by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

The limit with which $F_Q^W(Z)$ is compared varies inversely with power above 50% RTP and directly with the function K(Z) provided in the COLR.

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are taken for 61 core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 15% inclusive; and

b. Upper core region, from 85 to 100% inclusive.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

The top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. If $F_Q^W(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F_Q^M(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent $F_Q(Z)$ evaluations show an increase in the expression

$$\text{maximum over } z \quad \left[\frac{F_Q^C(Z)}{K(Z)}\right]$$

it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by an appropriate factor specified in the COLR, or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

During the power ascension following a refueling outage, startup physics testing program controls ensure that the $F_Q(Z)$ will not exceed the values assumed in the safety analysis. These controls include power distribution measurement, ramp rate restrictions, and restrictions on RCCA motion. They provide the necessary controls to precondition the fuel and ensure that the reactor power may be safely increased to equilibrium conditions at or near RTP, at which time $F_Q^W(Z)$ and AFD target band are determined. Performing the Surveillance within 12 hours after achieving equilibrium conditions after each refueling after THERMAL POWER exceeds 75% RTP, ensures that the $F_Q(Z)$ limit is met when the unit is released for normal operations.

If THERMAL POWER has been increased by $\geq$ 10% RTP since the last determination of $F_Q^W(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium condition at this higher power level (to ensure that $F_Q^W(Z)$ values are being reduced sufficiently with the power increase to stay within the LCO limits).

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances.

BASES (continued)

REFERENCES

1. USAR, Section 14.

2. AEC "General Design Criteria for Nuclear Power Plant Construction Permits", Criterion 29, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

3. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.

4. WCAP-10216-P-A, Revision 1A, "Relaxation of Constant Axial Offset Control/ FQ Surveillance Technical Specification," February 1994.

5. WCAP-12472-P-A, "Beacon Core Monitoring and Operation Support System", August 1994.

6. WCAP-12472-P-A, Addendum 1-A, "BEACON Core Monitoring and Operation Support System," January 2000.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution measurement obtained with either the movable incore detector system or the Power Distribution Monitoring System. Specifically, the results of the three dimensional power distribution measurement are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 effective full power days (EFPD). However, during power operation, the global power distribution is monitored by LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” and LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” which address directly and continuously measured process variables.

BASES

BACKGROUND (continued)

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling ratio (DNBR) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency (referred to as Condition II events). The departure from nucleate boiling (DNB) design basis precludes DNB and is met by limiting the minimum local DNB heat flux ratio to a value greater than the criterion listed in Reference 1. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Controlling $F^N_{\Delta H}$ precludes core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition during Condition II transients (Ref. 1);

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F (Ref. 1);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 1); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)

For transients that may be DNB limited, the THERMAL POWER, Reactor Coolant System flow, temperature, pressure and $F^N_{\Delta H}$ are the core parameters of most importance. Except for Static Rod Cluster Control Assembly (RCCA) Misalignment and Dropped Rod events, the limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any Condition II transients. The analyses for Static RCCA Misalignment and Dropped Rod events ensure the DNB design basis is met by assuming a conservatively large value for $F^N_{\Delta H}$. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion listed in Reference 1. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all Condition II transients, except Static RCCA Misalignment and Dropped Rod events, that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor $(F_Q(Z))$ and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 1).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” LCO 3.1.6, “Control Bank

BASES

APPLICABLE SAFETY ANALYSES (continued)

Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using either the movable incore detector system or the Power Distribution Monitoring System. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition I events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses as described in the Applicable Safety Analyses section above.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase by a factor specified in the COLR for every 1% RTP reduction in THERMAL POWER.

BASES (continued)

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1 and A.3

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1 and reduce the Power Range Neutron Flux -High trip setpoint to $\leq$ 55% RTP in accordance with Required Action A.3. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1 provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.3 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

BASES

ACTIONS (continued)

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1, a power distribution measurement (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by Action A.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the power distribution measurement, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.4

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is $\geq$ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

Condition A is modified by a Note that requires that Required Actions A.2 and A.4 must be completed whenever Condition A is entered.

BASES

ACTIONS (continued)

B.1

When Required Actions A.1 through A.4 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using either the movable incore detector system or the Power Distribution Monitoring System to obtain a power distribution measurement. A computer calculation determines the maximum value of $F^N_{\Delta H}$ from the measured power distribution. The measured value of $F^N_{\Delta H}$ must be increased by 4% (if using the movable incore detector system) or increased by $U_{\Delta H}$% (if using the Power Distribution Monitoring System, where $U_{\Delta H}$ is determined as described in References 3 and 4) to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation.

BASES (continued)

REFERENCES

1. USAR Section 14.
2. AEC "General Design Criteria for Nuclear Power Plant Construction Permits", Criterion 29, issued for comment July 10, 1967, as referenced in USAR Section 1.2.
3. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System", August 1994.
4. WCAP-12472-P-A, Addendum 1-A, "BEACON Core Monitoring and Operations Support System", January 2000.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

Relaxed Axial Offset Control (RAOC) is a calculational procedure that defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to ensure that the loss of coolant accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

The AFD is monitored on an automatic basis using the unit process computer, which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The AFD is a measure of axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations.

The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The RAOC methodology (Ref. 2) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the LOCA and loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.

The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition II, III, and IV events. This ensures that fuel cladding integrity is maintained for these postulated accidents. The most important Condition IV event is the loss of coolant accident. The most significant Condition III event is the loss of RCS flow accident. The most significant Condition II events are uncontrolled bank withdrawal at power and Rod Cluster Control Assembly (RCCA) misalignment.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator through the manual operation of the control banks or automatic motion of control banks. The automatic motion of the control banks is in response to temperature deviations resulting from manual operation of the Chemical and Volume Control System to change boron concentration or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors. Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as Δ flux or % ΔI.

Violating this LCO on the AFD could produce unacceptable consequences if a Condition II, III, and IV event occurs while the AFD is outside its specified limits.

APPLICABILITY

The AFD requirements are applicable in MODE 1 greater than or equal to 50% RTP when the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis.

For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.

BASES (continued)

ACTIONS

A.1

As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

This Surveillance verifies that the AFD, as indicated by the NIS excore channel, is within its specified limits. The Surveillance Frequency of 7 days is adequate considering that the AFD is monitored by a computer and any deviation from requirements is alarmed.

REFERENCES

1. WCAP-8403 (nonproprietary), “Power Distribution Control and Load Following Procedures,” Westinghouse Electric Corporation, September 1974.

2. WCAP-10216-P-A, Revision 1A, “Relaxation of Constant Axial Offset Control/ F_Q Surveillance Technical Specification,” February 1994.

3. USAR, Chapter 7.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Rod Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During transient conditions arising from events of moderate frequency (Condition II events), there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 200 cal/gm (Ref. 1); and

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 2).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure the assumptions used in the safety analysis remain valid by preventing an undetected change in the gross radial power distribution.

In MODE 1, the QPTR must be maintained within limits to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the assumptions in the safety analysis are possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to

BASES

APPLICABILITY (continued)

require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F_{\Delta H}^{N}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in the QPTR would require power reductions within 2 hours of QPTR determination, if necessary to comply with the decreased maximum allowable power level. Decreases in QPTR would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

After completion of Required Action A.1, the QPTR alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

BASES

ACTIONS (continued)

A.3

The peaking factor $F_Q(Z)$ (as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$) and $F_{\Delta H}^N$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F_{\Delta H}^N$ and $F_Q(Z)$ within the Completion Time of 24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to support a power distribution measurement using either the movable incore detector system or the Power Distribution Monitoring System. A Completion Time of 24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a power distribution measurement. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F_{\Delta H}^N$ and $F_Q(Z)$ for changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F_{\Delta H}^N$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the

BASES

ACTIONS

A.4 (continued)

power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limits prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by two Notes. Note 1 states that the QPTR is not restored to within limits until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents

BASES

ACTIONS

A.5 (continued)

exiting the Actions prior to completing a power distribution measurement, using either the movable incore detector system or the Power Distribution Monitoring System to verify peaking factors, per Required Action A.6. These Notes are intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the flux tilt is restored to within limits (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

BASES

ACTIONS (continued)

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 85% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency of 7 days takes into account other information and alarms available to the operator in the control room.

For those causes of a core power tilt that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the input from one or more Power Range Neutron Flux channel inputs are inoperable and the THERMAL POWER is > 85% RTP.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 at a Frequency of 12 hours provides an accurate alternative means for ensuring that the QPTR remains within its limits.

For purposes of monitoring changes in radial core power distribution when one power range channel is inoperable, the Power Distribution Monitoring System, or at least 2 movable incore detectors, or 4 thermocouples per quadrant may be used to calculate an incore core power tilt. This incore core power tilt may be used, instead of the excore detectors, to confirm that the QPTR is within the limits by comparing it to previous power distribution measurements.

REFERENCES

1. USAR, Section 14.

2. AEC "General Design Criteria for Nuclear Power Plant Construction Permits", Criterion 29, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

AEC GDC Criterion 14, "Core Protection Systems" (Ref. 1), requires that core protection systems, together with associated equipment, shall be designed to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits. The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting Safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

Technical specifications are required by 10CFR50.36 to contain LSSS defined by the regulation as "... settings for automatic protective devices ... so chosen that automatic protective action will correct the abnormal situation before a safety limit (SL) is exceeded." The analytical limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the analytical limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the analytical limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The trip setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable

BASES

BACKGROUND (continued)

reaching the analytical limit and thus ensuring that the SL would not be exceeded. As such, the trip setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the trip setpoint plays an important role in ensuring that SLs are not exceeded. As such, the trip setpoint meets the definition of an LSSS (Ref. 2) and could be used to meet the requirement that they be contained in the technical specifications.

Technical specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in technical specifications as "... being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and therefore the LSSS as defined by 10CFR50.36 is the same as the OPERABILITY limit for these devices. However, use of the trip setpoint to define OPERABILITY in technical specifications and its corresponding designation as the LSSS required by 10CFR50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as-found" value of a protective device setting during a surveillance. This would result in technical specification compliance problems, as well as reports and corrective actions required by the rule which are necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the trip setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the trip setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as-found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety

BASES

BACKGROUND (continued)

function and the only corrective action required would be to reset the device to the trip setpoint to account for further drift during the next surveillance interval.

Use of the trip setpoint to define “as-found” OPERABILITY and its designation as the LSSS under the expected circumstances described above would result in actions required by both the rule and technical specifications that are clearly not warranted. However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the technical specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS.

The Allowable Value specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the actual setting is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the trip setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a safety limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. Note that, although the channel is “OPERABLE” under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable from a technical specification perspective. This requires corrective action including those actions required by 10CFR50.36 when automatic protective devices do not function as required.

BASES

BACKGROUND (continued)

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits (Ref. 3) are:

1. The departure from nucleate boiling ratio (DNBR) shall be maintained to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 100 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. One acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS instrumentation is segmented into interconnected portions as described in the USAR (Ref. 4), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Reactor Protection Analog System and Nuclear Instrumentation System (NIS), arranged in protection channel sets: provides signal conditioning, bistable setpoint comparison, bistable electrical signal output to protection system relay logic, and control board/control room/miscellaneous indications;

BASES

BACKGROUND (continued)

3. Reactor Protection Relay Logic System, including channelized input and logic: initiates proper unit shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable outputs from the analog protection system and NIS; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the trip setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

Reactor Protection Analog and NI Systems

Generally, two to four channels of instrumentation are used for the signal processing of unit parameters measured by the field instruments. The instrument channels provide signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints that are based on safety analyses (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an

BASES

BACKGROUND

Reactor Protection Analog and NI Systems (continued)

output from a bistable actuates logic input relays. Channel separation is described in Reference 4. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the protection logic, main control board indication, and the plant computer. In addition, some provide input to one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function will still operate with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function will still operate with a one-out-of-two logic.

If a parameter is used for input to the protection logic and a control function, the circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. These requirements are described in IEEE-279-1971. Where necessary to provide the required reliability and redundancy, four channels with a two-out-of-four logic, or median signal selection and signal validation are provided. The actual number of channels required for each unit parameter is specified in Reference 4. Again, a single failure will neither cause nor prevent the protection function actuation.

Allowable Values and RTS Setpoints

The trip setpoints used in the bistables are based on the analytical limits from Reference 3. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration

BASES

BACKGROUND

Allowable Values and RTS Setpoints (continued)

tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49, the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservative with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Values and trip setpoints, including their explicit uncertainties, is provided in the plant specific setpoint methodology study (Ref. 5) which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each trip setpoint and corresponding Allowable Value. The trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value (LSSS) to account for measurement errors detectable by the COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

The trip setpoint is the value at which the bistable is set and is the expected value to be achieved during calibration. The trip setpoint value ensures the LSSS and the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as-left" setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + bistable setting uncertainties).

Trip setpoints consistent with the requirements of the Allowable Value ensure that SLs and DNBR limits are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed).

Each required instrument channel can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance

BASES

BACKGROUND

Allowable Values and RTS Setpoints (continued)

requirements of Reference 5. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The instrumentation for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

Reactor Protection Relay Logic System

The relay logic equipment uses outputs from the analog and NI bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own set of cabinets for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to provide a reactor trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The bistable outputs are combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Switchgear

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from

BASES

BACKGROUND

Reactor Trip Switchgear (continued)

the relay logic is a contact signal that energizes the undervoltage coils in the RTBs, and bypass breakers if in use. When the required logic matrix combination is completed, the relay logic output contacts open, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the relay logic. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself to open the RTBs, thus providing a diverse trip mechanism.

The logic matrix Functions are described in Reference 4. In addition to the reactor trip or ESF, Reference 4 also identifies the various "permissive interlocks" that are associated with unit conditions. Each train has built in test features that allow testing of the logic matrix Functions while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the SLs and DNBR limits during AOOs as identified in Reference 3 and mitigates the consequences of DBAs in all MODES in which the Rod Control System is capable of rod withdrawal or one or more rods not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The analysis described in Reference 3 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the safety analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

conditions that do not require dynamic transient analysis. They may also serve as backups to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. A channel is OPERABLE with an actual setpoint value outside its calibration tolerance provided the actual setpoint "as-found" value does not exceed its associated Allowable Value and provided the setpoint "as-left" value is adjusted to a value within the "as-left" calibration tolerance band. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of two, three, or four channels in each instrumentation Function, two channels of Manual Reactor Trip and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when RTS channels are also used as control system inputs and there is a possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection, even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its trip setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel activates the reactor trip breakers in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, Manual Reactor Trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the Manual Reactor Trip Function must also be OPERABLE if one or more shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, Manual Reactor Trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core, or all of the rods are inserted there is no need to be able to trip the reactor. In MODE 6, the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the Manual Reactor Trip Function is not required.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Reactor Trip System Functions (continued)

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the reactor control system. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor. While performing PHYSICS TESTS in accordance with LCO 3.1.8, the number of required channels may be reduced to three.

a. Power Range Neutron Flux-High

The Power Range Neutron Flux-High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux-High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux-High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range channels cannot indicate neutron levels in this range. In these MODES, the Power Range Neutron Flux-High does not have to be OPERABLE because the reactor is shut down

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Power Range Neutron Flux-High (continued)

and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

b. Power Range Neutron Flux-Low

The LCO requirement for the Power Range Neutron Flux-Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux-Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux P-10 setpoint, and in MODE 2, the Power Range Neutron Flux-Low trip must be OPERABLE. This Function may be manually blocked by the operator when two-out-of-four power range channels are greater than the P-10 setpoint. This Function is automatically unblocked when three-out-of-four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux-High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range channels cannot indicate neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Power Range Neutron Flux Rate

The Power Range Neutron Flux Rate trips use the same channels as discussed for Function 2 above.

a. Power Range Neutron Flux-High Positive Rate

The Power Range Neutron Flux-High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA rod drive housing rupture and the accompanying ejection of the RCCA and uncontrolled RCCA withdrawal at power. This Function compliments the Power Range Neutron Flux-High and Low Setpoint trip Functions to ensure that the criteria are met for a rod ejection from the power range.

The LCO requires all four of the Power Range Neutron Flux-High Positive Rate channels to be OPERABLE.

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident or uncontrolled RCCA withdrawal at power, the Power Range Neutron Flux-High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range channels cannot indicate neutron levels present in this mode.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Power Range Neutron Flux Rate (continued)

   b. Power Range Neutron Flux-High Negative Rate

   The Power Range Neutron Flux-High Negative Rate trip Function provides protection for rod drop events. Safety analysis results show that the core response from single rod drops, multiple rod drops and an entire bank drop does not result in a condition where the DNB design basis is violated. Operation of this Function is not required to meet the Condition II acceptance criteria for any credible rod drop event.

   The LCO requires all four Power Range Neutron Flux-High Negative Rate channels to be OPERABLE.

   In MODE 1 or 2, when there is potential for a rod drop event to occur, the Power Range Neutron Flux-High Negative Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-High Negative Rate trip Function does not have to be OPERABLE because the core is not critical and DNB is not a concern. In MODE 6, no rods are withdrawn and the required SDM is increased during refueling operations. In addition, the NIS power range channels cannot indicate neutron levels present in this MODE.

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function provides redundant protection to the Power Range Neutron Flux-Low Setpoint trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Intermediate Range Neutron Flux (continued)

do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal event during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux-High Setpoint trip and the Power Range Neutron Flux-High Positive Rate trip provide core protection for a rod withdrawal event. In MODE 2 below the P-6 setpoint, and in MODE 3, 4, or 5, the Source Range Neutron Flux Trip provides the core protection for reactivity events. The core also has the required SDM to mitigate the consequences of a positive reactivity addition event. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range channels cannot indicate neutron levels present in this MODE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition. This trip Function provides redundant protection to the Power Range Neutron Flux-Low trip Function. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5 when rods are capable of withdrawal or one or more rods are not fully inserted. Therefore, the functional capability at the specified trip setpoint is assumed to be available.

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events.

In MODE 2 when below the P-6 setpoint and in MODES 3, 4, and 5 when there is a potential for an uncontrolled RCCA bank rod withdrawal event the Source Range Neutron Flux trip must be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux-Low trip will provide core protection for reactivity events. Above the P-6 setpoint, the NIS source range detectors are de-energized .

In MODES 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs from the Function to RTS logic are not required to be OPERABLE.

The requirements for the NIS source range detectors to monitor core neutron levels and provide indication of reactivity changes

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Source Range Neutron Flux (continued)

that may occur as a result of events like a boron dilution are addressed in LCO 3.9.3, "Nuclear Instrumentation," for MODE 6.

6. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. The inputs to the Overtemperature ΔT trip include pressurizer pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature – the trip setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure – the trip setpoint is varied to correct for changes in system pressure; and

- axial power distribution – $f(\Delta I)$, the trip setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range channels. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range channels, the trip setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

The Overtemperature ΔT trip Function is calculated for each channel as described in Note 1 of Table 3.3.1-1. A trip occurs if Overtemperature ΔT is indicated in two channels. Since the pressure and temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the trip setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions. While performing PHYSICS TESTS in accordance with LCO 3.1.8, the number of required channels may be reduced to three.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also provides a backup to the Power Range Neutron Flux-High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature – the trip setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;
- rate of change of reactor coolant average temperature – including dynamic compensation for the delays between the core and the temperature measurement system; and

The Overpower ΔT trip Function is calculated for each channel as per Note 2 of Table 3.3.1-1. A trip occurs if Overpower ΔT is indicated in two channels. Since the temperature signals are used for other control functions, the actuation logic must be

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Overpower ΔT (continued)

able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

8. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure-High and-Low trips and the Overtemperature ΔT trip.

a. Pressurizer Pressure-Low

The Pressurizer Pressure-Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Pressurizer Pressure-Low (continued)

The LCO requires four channels of Pressurizer Pressure -Low to be OPERABLE. Since the pressurizer pressure channels are also used to provide input to the pressurizer pressure control system, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure- Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range or turbine impulse pressure). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, the AOO's meet their DNB criteria without requiring this trip function.

b. Pressurizer Pressure-High

The Pressurizer Pressure-High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the Pressurizer Pressure-High to be OPERABLE. Although the pressurizer pressure channels are also input to pressure control, an input failure to the control system can not cause a transient that would require actuation of this protection Function. Three OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Pressurizer Pressure-High (continued)

The Pressurizer Pressure-High Allowable Value is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure-High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure-High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

9. Pressurizer Water Level-High

The Pressurizer Water Level-High trip Function provides a backup signal for the Pressurizer Pressure-High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level-High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available,

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Pressurizer Water Level-High (continued)

pressure overshoot due to level channel failure cannot cause the safety valve to lift before the reactor high pressure trip.

In MODE 1, when there is a potential for transients such as a load rejection causing overfill of the pressurizer, the Pressurizer Water Level-High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

10. Reactor Coolant Flow-Low

The Reactor Coolant Flow-Low trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, a loss of flow in either RCS loop will actuate a reactor trip. Above the P-7 setpoint, a loss of flow in both RCS loops will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input. This flow is a percent of normal indicated loop flow as measured at loop elbow tap.

The LCO requires three Reactor Coolant Flow-Low channels per loop to be OPERABLE in MODE 1 above P-7 or P-8.

In MODE 1 above the P-7 or P-8 setpoints, a loss of flow in an RCS loop could result in DNB conditions in the core. Below the P-7 and P-8 setpoints, all reactor trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Loss of Reactor Coolant Pump (RCP)

Loss of RCP trip Function operates on two sets of auxiliary contacts, with one set on each RCP breaker. This Function anticipates the Reactor Coolant Flow-Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

a. Reactor Coolant Pump Breaker Open

The RCP Breaker Open trip Function provides protection against violating the DNBR limit due to a loss of flow in one or both RCS loop(s). The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. If both RCP breakers are open above the P-7 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low trip setpoint is reached.

The LCO requires one RCP Breaker Open channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow- Low trip alone provides sufficient protection of the DNBR limit for loss of flow events. The RCP Breaker Open trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump.

This Function measures only the discrete position (open or closed) of the RCP breaker, using position switches. Therefore, the Function has no adjustable trip setpoint with which to associate an allowable value.

In MODE 1 above the P-7 or P-8 setpoints, when a loss of low in either or both RCS loop(s) could result in DNB conditions in the core, the RCP Breaker Open trip must be OPERABLE.

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APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

a. Reactor Coolant Pump Breaker Open (continued)

Below the P-7 and P-8 setpoints, RCP Breaker Open reactor trips are automatically blocked since the analyses demonstrate AOOs meet their DNB criteria without requiring this trip function at this low power level. Above the P-7 or P-8 setpoints, the RCP Breaker Open reactor trips are automatically enabled.

b. Underfrequency 4 kV Buses 11 and 12 (21 and 22)

The Underfrequency 4 kV Buses 11 and 12 (21 and 22) breaker trip Function provides protection against violating the DNBR limit due to a loss of flow in both RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. A loss of frequency detected on both RCP buses will initiate a trip of both RCP breakers. This trip will generate a reactor trip before the Reactor Coolant Flow-Low trip setpoint is reached. Time delays are incorporated into the Underfrequency 4 kV Buses 11 and 12 (21 and 22) channels to prevent RCP breaker trips due to momentary electrical power transients.

The LCO requires two underfrequency channels per bus to be OPERABLE.

In MODE 1 above the P-7 or P-8 setpoints, the Underfrequency 4 kV Buses 11 and 12 (21 and 22) trip Function must be OPERABLE. Below the P-7 and P-8 setpoints, reactor trips on RCP Breaker Open are automatically blocked since the AOOs meet their DNB criteria without requiring this trip Function at this low

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APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

12. Undervoltage on 4 kV Buses 11 and 12 (21 and 22)

power level. Above the P-7 or P-8 setpoints, the reactor trips on RCP Breaker Open are automatically enabled.

The Undervoltage on 4 kV Buses 11 and 12 (21 and 22) Function provides protection against violating the DNBR limit due to a loss of flow in both RCS loops. The voltage to each loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on both RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low trip setpoint is reached. Time delays are incorporated into the undervoltage channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires two undervoltage channels per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the undervoltage trip must be OPERABLE. Below the P-7 setpoint, reactor trips on undervoltage are automatically blocked since analyses demonstrate AOOs meet their DNB criteria without requiring this trip Function at this low power level. Above the P-7 setpoint, the reactor trip on undervoltage in both RCS loops is automatically enabled. This Function uses the same relays as the ESFAS Function 6.d, “Undervoltage on 4 kV Buses 11 and 12 (21 and 22)” start of the turbine driven auxiliary feedwater pump.

13. Steam Generator (SG) Water Level-Low Low

The SG Water Level-Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the Auxiliary Feedwater (AFW) System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

13. Steam Generator (SG) Water Level-Low Low (continued)

water. A narrow range low low level in either SG indicates a potential loss of heat sink for the reactor. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level-Low Low per SG to be OPERABLE. The level channels provide input to the SG level control system. However, median signal selection ensures that the failure of a single channel will not result in a low level which may require the protection function actuation. Therefore, only three channels per SG are required to be OPERABLE.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level-Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). Generally the MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level-Low Low Function does not have to be OPERABLE because the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System or by the Residual Heat Removal (RHR) System in MODE 3, 4, 5, or 6.

14. Turbine Trip

a. Turbine Trip-Low Autostop Oil Pressure

The Turbine Trip-Low Autostop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip

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APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

a. Turbine Trip-Low Autostop Oil Pressure (continued)

Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint will not actuate a reactor trip. Three pressure switches monitor the autostop oil pressure in the turbine electrohydraulic control system. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip-Low Autostop Oil Pressure to be OPERABLE in MODE 1 above P-9.

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip-Low Autostop Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip-Turbine Stop Valve Closure

The Turbine Trip-Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-9 setpoint. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Turbine Trip-Turbine Stop Valve Closure (continued)

operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip-Low Autostop Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch channel that inputs to the RTS relay logic. If the limit switches indicate that both stop valves are closed, a reactor trip is initiated.

The allowable value for this Function is set to assure channel trip occurs when the associated stop valve is closed.

The LCO requires two Turbine Trip-Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. Both channels to a train of relay logic must trip to cause reactor trip.

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip-Stop Valve Closure trip Function does not need to be OPERABLE.

15. Safety Injection (SI) Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation relay logic will initiate a reactor trip upon any signal that initiates SI. This is not a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

15. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (continued)

except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present. Allowable Values are not applicable to this Function. The SI Input is provided by relays in the ESFAS. Therefore, there is no measurement signal with which to associate an Allowable Value.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

16. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed.

Each interlock Function consists of the following circuitry:

- The bistables that provide the applicable process parameter input;

- Logic input relays and contact matrix; and

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

16. Reactor Trip System Interlocks (continued)

- Permissive (P) relays that provide the interlock to the appropriate trip logic.

The interlock Functions are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed; and

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Intermediate Range Neutron Flux, P-6 (continued)

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary. In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either Power Range Neutron Flux or Turbine Impulse Pressure. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (both loops);
- RCPs Breaker Open (both loops); and
- Undervoltage 4 kV Buses 11 and 12 (21 and 22).

These reactor trips are only required when operating above the P-7 setpoint. The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Low Power Reactor Trips Block, P-7 (continued)

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure- Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (both loops);
- RCP Breaker Position (both loops); and
- Undervoltage 4 kV Buses 11 and 12 (21 and 22).

The associated trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below the P-7 setpoint, which is in MODE 1.

1. Power Range Neutron Flux, P-7

Power Range Neutron Flux, P-7 is actuated by two-out-of-four NIS power range channels. The LCO requirement for this Function ensures that this input to the P-7 interlock is available.

The LCO requires four channels of Power Range Neutron Flux, P-7 to be OPERABLE in MODE 1.

OPERABILITY in MODE 1 ensures the Function is available to perform its increasing power Functions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Turbine Impulse Pressure, P-7

The Turbine Impulse Pressure, P-7 is actuated by one-out-of-two pressure channels. The LCO requirement for this Function ensures that this input to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure, P-7 to be OPERABLE in MODE 1. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated by two-out-of-four NIS power range channels. The P-8 interlock automatically enables the Reactor Coolant Flow-Low (single loop) and RCP Breaker Open (single loop) reactor trips on low flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than the P-8 setpoint. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock is actuated by two-out-of-four NIS power range channels. The LCO requirement for this Function ensures that the Turbine Trip-Low Autostop Oil Pressure and Turbine Trip-Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip could cause a load rejection beyond the capacity of the steam dump and Rod Control Systems. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1.

In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the steam dump and Rod Control Systems, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the steam dump system.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated by two-out-of-four NIS power range channels. If power level falls below the setpoint on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal;

- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux-Low reactor trip;

- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors; and

- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux-Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2. OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux-Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection. While performing PHYSICS TESTS in accordance with LCO 3.1.8, the number of required channels may be reduced to three.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip Breakers

The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker or main breaker and bypass breaker, depending upon the system configuration. Two OPERABLE trains ensure no single random failure can disable the RTS trip capability. The OPERABILITY requirement for the individual trip mechanisms is provided in the Function 18 below.

This trip Function must be OPERABLE in MODE 1 or 2. This ensures it is available when the reactor is critical. In MODE 3, 4, or 5, this RTS trip Function must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 17 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2. This ensures they are available when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

19. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 17 and 18) and Automatic Trip Logic (Function 19) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

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

This trip Function must be OPERABLE in MODE 1 or 2. This ensures it is available when the reactor is critical. In MODE 3, 4, or 5, this RTS trip Function must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods not fully inserted.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO

BASES

ACTIONS (continued)

Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.1-1 are specified (e.g., on a per steamline, per loop, per SG, etc., basis), then the Condition may be entered separately for each steamline, loop, SG, etc., as applicable.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit may be outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the Reactor Protection Relay Logic for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

BASES

ACTIONS

B.1 and B.2 (continued)

If the channel cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, Action C would apply to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

C.1 , C.2.1 and C.2.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the RTS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the

BASES

ACTIONS

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

same 48 hours to ensure that all rods are fully inserted and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1.1, D.1.2, and D.2

Condition D applies to the following reactor trip Functions:

- Power Range Neutron Flux-High Function;
- Power Range Neutron Flux-Low;
- Power Range Neutron Flux-High Positive Rate;
- Power Range Neutron Flux-High Negative Rate.

The NIS power range detectors provide input to the reactor control system and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-10271-P-A (Ref. 6).

BASES

ACTIONS

D.1.1, D.1.2, and D.2 (continued)

In addition to placing the inoperable channel in the tripped condition, monitor the QPTR once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels > 85% RTP. The 12 hour Frequency is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

If Condition D is entered while performing PHYSICS TESTS in accordance with LCO 3.1.8, a total of two channels may be inoperable.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 4 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 4 hour time limit is justified in Reference 6.

Required Action D.1.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if THERMAL POWER is > 85% RTP and the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function

BASES

ACTIONS

D.1.1, D.1.2, and D.2 (continued)

inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the core power distribution measurement information once per 12 hours may not be necessary.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure-High; and
- SG Water Level-Low Low.

A known inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 6.

If the operable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up

BASES

ACTIONS

E.1 and E.2 (continued)

to 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 6.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range channel performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase THERMAL POWER above the P-10 setpoint. These actions are consistent with the provisions of LCO 3.0.4 which stats, "This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS . . ." The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range channels perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

BASES

ACTIONS (continued)

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range channel performs the monitoring Functions.

With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

Required Action G.1 is modified by a Note to indicate that normal plant control operations that individually add limited reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided they are accounted for in the calculated SDM.

H.1

Condition H applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

BASES

ACTIONS

H.1 (continued)

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is reduced and any actions that add positive reactivity to the core must be suspended immediately.

Required Action H.1 is modified by a Note to indicate that normal plant control operations that individually add limited reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided they are accounted for in the calculated SDM.

I.1

Condition I applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, or in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition.

J.1 and J.2

Condition J applies to one inoperable source range channel in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an

BASES

ACTIONS

J.1 and J.2 (continued)

OPERABLE status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour are justified in Reference 6.

K.1 and K.2

Condition K applies to the following reactor trip Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (single loop); and
- Reactor Coolant Flow-Low (both loops).

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 or P-8 setpoints. These Functions do not have to be OPERABLE below the P-7 and P-8 setpoints because there are no loss of flow trips below these setpoints. There is insufficient heat production to generate DNB conditions below these setpoints. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 6. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 and P-8 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

BASES

ACTIONS

K.1 and K.2 (continued)

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channels, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 6.

L.1 and L.2

Condition L applies to the Loss of Reactor Coolant Pump Underfrequency 4 kV Buses 11 and 12 (21 and 22) and Undervoltage on 4 kV Buses 11 and 12 (21 and 22). With one or both channels inoperable on one bus, the inoperable channel(s) must be placed in trip within 6 hours. If the channel(s) cannot be restored to OPERABLE status or the channel(s) placed in trip within the 6 hours, then THERMAL POWER must be reduced below the P-7 and P-8 setpoints within the next 6 hours. This places the unit in a MODE where the LCO is no longer applicable. These trip Functions do not have to be OPERABLE below the P-7 and P-8 setpoints because analyses demonstrate AOOs meet their DNB criteria without requiring these trip functions at this low power level. The 6 hours allowed to restore the channel(s) to OPERABLE status or place in trip and the 6 additional hours allowed to reduce THERMAL POWER to below the P-7 and P-8 setpoints are justified in Reference 6.

The Required Actions have been modified by a Note that allows placing one inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 6.

BASES

ACTIONS (continued)

M.1 and M.2

Condition M applies to the RCP Breaker Open reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains, other breaker position channels, other flow related trip Functions and the low probability of an event occurring during this interval.

If the channel cannot be restored to OPERABLE status within the 48 hours, then THERMAL POWER must be reduced below the P-7 and P-8 setpoints within the next 6 hours. This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-7 and P-8 setpoints because analyses demonstrate AOOs meet their DNB criteria without requiring this Trip Function at this low power level.

N.1 and N.2

Condition N applies to Turbine Trip on Low Autostop Oil Pressure or on Turbine Stop Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 6 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 6 hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the 6 hours allowed for reducing power are justified in Reference 6.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channel(s). The 4 hour time limit is justified in Reference 6.

BASES

ACTIONS (continued)

O.1 and O.2

Condition O applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action O.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours (Required Action O.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of an additional 6 hours (Required Action O.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 8 hours for surveillance testing, provided the other train is OPERABLE. A train is normally bypassed by placing the bypass breaker in service and opening the associated RTB. The RTB remains OPERABLE under these conditions so that entry into Condition P is not required while performing testing allowed by this Note.

P.1 and P.2

Condition P applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one RTB train inoperable, 1 hour is allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of an additional 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 7 hour Completion Times are equal to the

BASES

ACTIONS

P.1 and P.2 (continued)

time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function. Placing the unit in MODE 3 results in Action C entry while RTB(s) are inoperable.

When the Automatic Relay Logic train associated with a RTB train is inoperable and Condition O has been entered, the RTB is normally bypassed by placing the bypass breaker in service and opening the associated RTB. The RTB remains OPERABLE under these conditions so that entry into Condition P is not required.

The Required Actions have been modified by two Notes. Note 1 allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. Note 2 allows one RTB to be bypassed for up to 4 hours for maintenance on undervoltage or shunt trip mechanisms if the other train is OPERABLE.

Q.1 and Q.2

Condition Q applies to the P-6 and P-10 interlocks. With one or more channel(s) inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status ensures the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of an additional 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 7 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

BASES

ACTIONS (Continued)

R.1 and R.2

Condition R applies to the P-7, P-8, and P-9 interlocks. With one or more channel(s) inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status ensures the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of an additional 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

S.1 and S.2

Condition S applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of an additional 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

With the unit in MODE 3, Action C would apply to any inoperable RTB Trip mechanism. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance of the diverse features is 4 hours, per Condition P.

BASES

ACTIONS

S.1 and S.2 (continued)

The Completion Time of 48 hours for Required Action S.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of reactor protection analog system supplies both trains of the RTS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 Effective Full Power Days (EFPD). If the absolute difference is ≥ 2%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 2%.

Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 15% RTP and that 72 hours is allowed for performing the first Surveillance after reaching 15% RTP.

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 31 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Verification of the shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test. When performing this SR, manually trip the UV trip attachment remotely (i.e., from the protection system racks). A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The RTS relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All logic combinations, with applicable permissives, are tested for each protection function required for the current plant MODE. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 75% RTP and that 24 hours is allowed for performing the first surveillance after reaching 75% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 92 days. A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions. Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

The difference between the current "as-found" values and the previous test "as-left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The "as-found" and "as-left" values must also be recorded and reviewed for consistency with the assumptions of Reference 5.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

The Frequency of 92 days is justified in Reference 6.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by two Notes. Note 1 requires that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. Verification that P-6 and P-10 are in their required state for existing plant conditions can also be accomplished by observation of the permissive annunciator window. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions. Note 2 provides an exception from performance of this SR prior to reactor startup for the intermediate and source range instrumentation when the reactor has been shutdown less than or equal to 48 hours. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within the previous 92 days. The Frequency of "prior to reactor startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of 12 hours after reducing power below P-10 (applicable to intermediate and power range low channels) and 4 hours after reducing power below P-6 (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and twelve and four hours after reducing power below P-10 or P-6, respectively. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than twelve hours or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the time limit. Twelve hours and four hours are reasonable times to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 12 and 4 hours, respectively.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 6. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to undervoltage and underfrequency relays, setpoint verification is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor where applicable (e.g., the undervoltage and underfrequency relays do not have separate sensors). The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. The difference between the current “as found” values and the previous test “as left” values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. This Surveillance includes verification that the time constants, where applicable, are adjusted to the prescribed values. The CHANNEL CALIBRATION for the power range neutron detectors is performed in accordance with SR 3.3.1.2 and SR 3.3.1.6. The 24 month Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR is modified by a Note stating that this test shall include verification of the RCS resistance temperature detector (RTD) bypass loop flow rate. This Surveillance includes verification that the time constants, where applicable, are adjusted to the prescribed values.

The Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RTS interlocks every 24 months. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions. This TADOT is performed every 24 months. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers. The Reactor Trip Bypass Breaker test shall include testing of the undervoltage trip.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.14 (continued)

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This test shall verify OPERABILITY by actuation of the end device. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions. This test is performed prior to exceeding P-9 interlock whenever the unit has been in MODE 3. This Surveillance is required if not performed within the previous 31 days. A Note states that verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.16

SR 3.3.1.16 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in appropriate plant procedures. Individual component response times are typically not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the equipment reaches the required functional state.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

Response time test is performed with the time constants set to their nominal value, provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

Testing of the final actuation devices is included in the testing. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.1.16 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 14, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation."

3. USAR, Section 14.

4. USAR, Section 7.

5. "Engineering Manual Section 3.3.4.1, Engineering Design Standard for Instrument Setpoint/Uncertainty Calculations".

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

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

AEC GDC Criterion 15, "Engineered Safety Features Protection Systems" (Ref. 1), requires that protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features to mitigate accidents.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. One acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 50.67 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The ESFAS instrumentation is segmented into interconnected portions as described in the USAR (Ref. 2), and as identified below:

1. Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;

2. Signal processing equipment including Reactor Protection Analog System, arranged in protection channel sets: provide signal conditioning, bistable setpoint comparison, bistable electrical signal output to engineered safety features (ESF) relay logic, and control board/control room/miscellaneous indications; and

3. ESF relay logic system including channelized input and logic: initiates the proper ESF actuation in accordance with the defined logic and based on the bistable outputs from the analog protection system.

BASES

BACKGROUND (continued)

The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for ESFAS action to prevent exceeding acceptable limits such that the consequences of Design Basis Accidents (DBAs) will be acceptable. The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although a channel is “OPERABLE” under these circumstances, the ESFAS setpoint must be left adjusted to within the established calibration tolerance band of the ESFAS setpoint in accordance with the uncertainty assumptions stated in the referenced setpoint methodology, (as-left criteria) and confirmed to be operating within the statistical allowances of the uncertainty terms assigned.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, for the ESFAS Functions, generally two or three field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Allowable Values. The OPERABILITY of each transmitter or sensor is determined by either “as-found” calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor, as related to channel behavior observed during performance of the CHANNEL CHECK.

Reactor Protection Analog System

Generally, for ESFAS Functions, two or three channels of instrumentation are used for the signal processing of unit parameters measured by the field instruments. The instrument channels provide

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BACKGROUND

Reactor Protection Analog System (continued)

signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints that are based on safety analyses (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable actuates logic input relays. Channel separation is described in Reference 2.

Generally, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function will still operate with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function will still operate with a one-out-of-two logic. Therefore, a single failure will neither cause nor prevent the protection function actuation. The actual number of channels required for each unit parameter is specified in Reference 2.

Allowable Values and ESFAS Setpoints

The trip setpoints used in the bistables are based on the analytical limits from Reference 3. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49, the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservative with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Value and ESFAS setpoints, including their explicit uncertainties, is provided in the plant specific setpoint methodology study (Ref. 4) which incorporates all the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the

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BACKGROUND

Allowable Values and ESFAS Setpoints (continued)

determination of each ESFAS setpoint and corresponding Allowable Value. The nominal ESFAS setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the ESFAS Function is considered OPERABLE.

The ESFAS setpoints are the values at which the bistables are set and is the expected value to be achieved during calibration. The ESFAS setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the “as-left” setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e. calibration tolerance uncertainties).

Setpoints adjusted consistent with the requirements of the Allowable Value ensure that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 4. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

ESF Relay Logic System

The relay logic equipment uses outputs from the analog bistables. To meet the redundancy requirements, two trains of relay logic, each

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BACKGROUND

ESF Relay Logic System (continued)

performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. Each train is packaged in its own set of cabinets for physical and electrical separation to satisfy separation and independence requirements.

The ESF relay logic system performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room of the unit. The relay logic consists of input, master and slave relays. The bistable outputs are combined via the input relays into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the appropriate master and slave relays are energized. The master and slave relays cause actuation of those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each relay logic train has built in test features that allow testing the decision logic matrix and some master and slave relay functions while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident.

An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Low Pressure is a primary actuation signal for loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) inside containment. Functions such as manual initiation, not specifically credited in the safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. A channel is OPERABLE with a trip setpoint outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to within the calibration tolerance band. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of two or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three configuration allows one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

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

1. Safety Injection

   Safety Injection (SI) provides two primary functions:

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

   2. Boration to ensure recovery and maintenance of SDM.

   These functions are necessary to mitigate the effects of a LOCA or SLB, both inside and outside of containment. The SI signal is also used to initiate other functions such as:

   - Containment Isolation;
   - Containment Ventilation Isolation;
   - Reactor Trip;
   - Feedwater Isolation;
   - Auxiliary Feedwater (AFW); and
   - Control room ventilation isolation.

   These other functions ensure:

   - Isolation of nonessential systems through containment penetrations;
   - Trip of the reactor to limit power generation;
   - Isolation of main feedwater to limit secondary side mass contribution to containment pressurization;
   - Start of AFW to ensure secondary side cooling capability;

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

- Isolation of the control room to ensure habitability.

a. Safety Injection-Manual Initiation

The LCO requires two channels to be OPERABLE. The operator can initiate SI at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

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

Each channel consists of one switch and the interconnecting wiring to the actuation logic cabinet. Each switch actuates both trains. This configuration does not allow testing at power. The Applicability of the SI Manual Initiation Function is discussed with the Automatic Actuation Relay Logic Function below.

b. Safety Injection-Automatic Actuation Relay Logic

This LCO requires two trains to be OPERABLE. The SI actuation logic consists of all circuitry housed within the ESF relay logic cabinets for the SI actuation subsystem, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Safety Injection-Automatic Actuation Relay Logic (continued)

Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation switches. Automatic actuation relay logic must be OPERABLE in MODE 4 to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection-High Containment Pressure

This signal provides protection against the following accidents:

- SLB inside containment; and
- LOCA.

Three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters and electronics are located outside of

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Safety Injection-High Containment Pressure (continued)

containment with the sensing line located inside containment. Thus, the high pressure Function will not experience any adverse environmental conditions and the Allowable Value reflects only steady state instrument uncertainties.

High Containment Pressure must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. In MODES 4, 5, and 6, plant conditions are such that the probability of an event requiring Emergency Core Cooling System (ECCS) injection is extremely low. In MODE 4, adequate time is available to manually actuate required components in the event of a DBA.

d. Safety Injection-Pressurizer Low Pressure

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- Rupture of a control rod drive mechanism housing (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Safety Injection-Pressurizer Low Pressure (continued)

- LOCAs; and
- SG Tube Rupture.

Pressurizer pressure provides both control and protection functions: input to the pressurizer pressure control system, reactor trip, and SI. However, two independent Power Operated Relief Valve (PORV) open signals must be present before a PORV can open. Therefore, a single pressure channel failing high will not fail a PORV open and trigger a depressurization event, which may then require SI actuation. Thus, three OPERABLE channels are sufficient to satisfy the protective requirements with a two-out-of-three logic.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 with pressurizer pressure ≥ 2000 psig to mitigate the consequences of a LOCA. This signal may be manually blocked by the operator when pressurizer pressure is < 2000 psig. Automatic SI actuation below this pressure setpoint is then performed by the High Containment Pressure signal.

This Function is not required to be OPERABLE in MODE 3 when pressurizer pressure is < 2000 psig. Other ESF

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Safety Injection-Pressurizer Low Pressure (continued)

functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection-Steam Line Low Pressure

Steam Line Low Pressure provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG safety valve.

Steam line pressure transmitters provide input to control functions, but the control function cannot initiate events that the Function acts to mitigate. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

With the transmitters typically located in the vicinity of the main steam lines, it is possible for them to experience adverse environmental conditions during a secondary side break. There is no event where the Steam Line Low Pressure instrumentation is credited to function under a harsh environmental condition. Therefore, the Allowable Value reflects steady state environmental instrument uncertainties.

This Function is anticipatory in nature and has a typical lead/lag ratio of 12/2.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Safety Injection-Steam Line Low Pressure (continued)

Steam Line Low Pressure must be OPERABLE in MODES 1, 2, and 3 with pressurizer pressure ≥ 2000 psig, when a secondary side break or stuck open safety valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator when pressurizer pressure is < 2000 psig. When pressurizer pressure is < 2000 psig, feed line break is not a concern. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

2. Containment Spray

Containment Spray (CS) provides three primary functions:

1. Lowers containment pressure and temperature after a LOCA or SLB in containment;

2. Reduces the amount of radioactive iodine in the containment atmosphere (although, this is not credited in the radiological consequence analysis); and

3. Adjusts the pH of the water in the containment sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure; and

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Containment Spray (continued)

- Minimize corrosion of the components and systems inside containment following a LOCA.

The CS actuation signal starts the CS pumps and aligns the discharge of the pumps to the CS nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the CS pumps and mixed with a sodium hydroxide solution from the spray additive tank. Containment spray is actuated manually or by High High Containment Pressure.

a. Containment Spray-Manual Initiation

The LCO requires two channels to be OPERABLE. The operator can initiate CS at any time from the control room by simultaneously turning two CS actuation switches. Because an inadvertent actuation of CS could have such serious consequences, two switches must be turned simultaneously to initiate both trains of CS. The inoperability of either switch may fail both trains of manual initiation.

Each channel consists of one switch and the interconnecting wiring to the actuation logic cabinets. The Applicability of the CS Manual Initiation Function is discussed with the Automatic Actuation Relay Logic Function below. Note that manual initiation of CS also actuates containment ventilation isolation.

b. Containment Spray-Automatic Actuation Relay Logic

The CS actuation logic consists of all circuitry housed within the ESF relay logic cabinets for the CS actuation subsystem, in the same manner as described for ESFAS Function 1.b.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. <u>Containment Spray-Automatic Actuation Relay Logic</u> (continued)

Manual and automatic initiation of CS must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA by the use of the manual actuation switches. Automatic actuation relay logic must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. <u>Containment Spray-High High Containment Pressure</u>

This signal provides protection against a LOCA or an SLB inside containment. The transmitters and electronics are located outside of containment with the sensing lines located inside containment. Thus, they will not experience any adverse environmental conditions and the Allowable Value reflects only steady state instrument uncertainties.

This is one of the only Functions that requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate CS, since the consequences of an inadvertent actuation of CS could be serious.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Containment Spray-High High Containment Pressure (continued)

High High Containment Pressure uses three sets of two channels, each set combined in a one-out-of-two configuration, with these outputs combined so that three sets tripped initiates CS. This arrangement exceeds the minimum redundancy requirements. High High Containment Pressure must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to overpressurize containment.

3. Containment Isolation

Containment Isolation (CI) provides isolation of the containment atmosphere, and process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a LOCA.

The CI signal isolates all automatically isolable process lines except instrument air and main steam lines, which require a steam line isolation signal.

a. Containment Isolation-Manual Initiation

Manual CI is actuated by either of two switches in the control room. Either switch actuates both trains. Note that manual initiation of CI also actuates Containment Ventilation Isolation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Containment Isolation-Manual Initiation (continued)

The LCO requires two channels to be OPERABLE. Each channel consists of one switch and the interconnecting wiring to the actuation logic cabinets. The Applicability of the CI Manual Initiation Function is discussed with the Automatic Actuation Relay Logic Function below.

b. Containment Isolation - Automatic Actuation Relay Logic

The CI actuation logic consists of all circuitry housed within the ESF relay logic cabinets for the CI actuation subsystem in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of CI must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a CI, actuation is simplified by the use of the manual actuation switches.

Automatic actuation relay logic must be OPERABLE in MODE 4 to support system manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems, in the event of a line break, to pressurize the containment to require CI. There is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Containment Isolation - Safety Injection

Containment Isolation is initiated by all Functions that initiate SI via the SI signal. The CI requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, at most. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the non-return check valves or the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident.

a. Steam Line Isolation – Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are two switches in the control room, one for each MSIV. The LCO requires one channel per loop to be OPERABLE.

b. Steam Line Isolation – Automatic Actuation Relay Logic

The steam line isolation actuation logic consists of all circuitry housed within the ESF relay logic cabinets for the steam line isolation subsystem in the same manner as described for ESFAS Function 1.b.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Steam Line Isolation (continued)

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless both MSIVs are closed. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB releasing significant quantities of energy.

c. Steam Line Isolation – High High Containment Pressure

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor. Three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. The transmitters and electronics are located outside containment with the sensing line located inside containment. Thus, they will not experience any adverse environmental conditions, and the Allowable Value reflects only steady state instrument uncertainties.

High High Containment Pressure must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless both MSIVs are closed. In MODES 4, 5, and 6, there

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Steam Line Isolation-High High Containment Pressure (continued)

is not enough energy in the primary and secondary sides to over pressurize containment.

d. Steam Line Isolation-High Steam Flow Coincident With Safety Injection and Coincident With Low Low T_{avg}

This Function provides closure of the MSIVs during an SLB or inadvertent opening of an SG safety valve to maintain at least one unfaulted SG as a heat sink for the reactor.

Two steam line flow channels per steam line are required OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation.

The High Steam Flow Allowable Value is a ΔP corresponding to $\leq$ 9.18E5 lb/hr at 1005 psig.

The main steam line isolates if the High Steam Flow signal occurs coincident with an SI signal and Low Low RCS average temperature. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Steam Line Isolation- High Steam Flow Coincident With Safety Injection and Coincident With Low Low T_{avg} (continued)

Two channels of T_{avg} per loop are required to be OPERABLE. The T_{avg} channels are combined in a logic such that two channels tripped cause a trip for the parameter. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of two OPERABLE channels per loop in a two-out-of-four configuration ensures no single random failure disables the Low Low T_{avg} Function. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

With the T_{avg} resistance temperature detectors (RTDs) located inside the containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Allowable Value reflects both steady state and adverse environmental instrumental uncertainties. This Function must be OPERABLE in MODES 1 and 2, and in MODE 3, when T_{avg} is above 520°F, when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless both MSIVs are closed. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Steam Line Isolation- High High Steam Flow Coincident With Safety Injection

This Function provides closure of the MSIVs during a SLB to maintain at least one unfaulted SG as a heat sink for the reactor.

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements.

The Allowable Value for High High Steam Flow is a ΔP corresponding to ≤ 4.5E6 lb/hr at 735 psig.

With the transmitters located inside containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Allowable Value reflects both steady state and adverse environmental instrument uncertainties.

The main steam lines isolate if the High High Steam Flow signal occurs coincident with an SI signal. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Steam Line Isolation-High High Steam Flow Coincident With Safety Injection (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break could result in rapid depressurization of the steam lines unless both MSIVs are closed. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

5. Feedwater Isolation

The primary function of the Feedwater Isolation signal is to limit containment pressurization during an SLB. This Function also mitigates the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

The Function performs the following:

- Trips the main turbine;
- Trips the main feedwater (MFW) pumps; and
- Shuts the MFW regulating valves (MFRVs) and the MFRV bypass valves.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Feedwater Isolation (continued)

This Function is actuated by High High SG Water Level, or by an SI signal. In the event of SI, the unit is taken off line. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

a. Feedwater Isolation-Automatic Actuation Relay Logic

The feedwater isolation actuation logic consists of all circuitry housed within the ESF relay logic cabinets for the feedwater isolation subsystem, in the same manner as described for ESFAS Function 1.b.

This Function must be OPERABLE in MODES 1, 2, and 3, except when all MFRVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve, when a secondary side break could result in significant containment pressurization. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

b. Feedwater Isolation-High High Steam Generator Water Level

This signal provides protection against excessive feedwater flow. The SG water level instruments provide input to the Feedwater Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Median signal selection

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Feedwater Isolation-High High Steam Generator Water Level (continued)

is used in the Feedwater Control System. Thus, three OPERABLE channels are sufficient to satisfy the requirements with a two-out-of-three logic. The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Allowable Value reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1 and 2, except when all MFRVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve. In MODES 3, 4, 5, and 6, the MFW System and the turbine generator are normally not in service and this Function is not required to be OPERABLE.

c. Feedwater Isolation-Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI via the SI signal. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has a motor driven pump and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST) (not safety related). Upon low level in the CST, the operators can manually realign the pump suctions to the Cooling Water (CL) System (safety related). The AFW System is aligned so that upon a pump start, flow is initiated to the SGs immediately.

a. Auxiliary Feedwater-Automatic Actuation Relay Logic

The auxiliary feedwater actuation logic consists of all circuitry housed within the reactor protection relay logic cabinets for the auxiliary feedwater actuation subsystem.

b. Auxiliary Feedwater-Low Low Steam Generator Water Level

Low Low SG Water Level provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. The SG water level instruments provide input to the Feedwater Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system, which may then require a protection function actuation, and a single failure in the other channels

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Auxiliary Feedwater-Low Low Steam Generator Water Level

providing the protection function actuation. Median signal selection is used in the Feedwater Control System. Thus, three OPERABLE channels per SG are sufficient to satisfy the requirements with a two-out-of-three logic.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. Auxiliary Feedwater-Safety Injection

An SI signal starts the motor driven and turbine driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

Functions 6.a through 6.c must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. Low Low SG Water Level in any operating SG will cause the AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Auxiliary Feedwater-Undervoltage on 4kV Buses 11 and 12 (21 and 22)

A loss of power on the buses that provide power to the MFW pumps provides indication of a pending loss of MFW flow. The undervoltage Function senses the voltage upstream of each MFW pump breaker. A loss of power for both MFW pumps will start the turbine driven AFW pump to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

e. Auxiliary Feedwater-Trip of Both Main Feedwater Pumps

A trip of both MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Motor driven MFW pumps are equipped with a breaker position sensing device. An open supply breaker indicates that the MFW pump is not running. Two-OPERABLE channels per AFW pump provide a start signal to each AFW pump in two-out-of-two taken once logic. A trip of both MFW pumps starts the motor driven and turbine driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Functions 6.d and 6.e must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus neither the pump

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY	6. Auxiliary Feedwater (continued) trip or bus undervoltage are indicative of a condition requiring automatic AFW initiation. Also, in MODE 2 the AFW system may be used for SG level control. The MFW trip is bypassed by placing the AFW pump CS in shutdown auto when AFW is aligned for this purpose. Low low SG level provides protection during this operation. The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit may be outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

BASES

ACTIONS

A.1 (continued)

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1, and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray (CS); and
- Containment Isolation (CI).

This action addresses the train orientation of the ESF relay logic for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE for each Function (except for CS), and the low probability of an event occurring during this interval. If the channel cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

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

Condition C applies to the automatic actuation relay logic for the following functions:

- SI;
- CS; and
- CI

This action addresses the train orientation of the ESF relay logic. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (12 hours total time) and in MODE 5 within an additional 30 hours (42 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 5) that 8 hours is the average time required to perform relay logic train surveillance.

BASES

ACTIONS (continued)

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

Condition D applies to:

- High Containment Pressure;
- Pressurizer Low Pressure;
- Steam Line Low Pressure;
- Steam Line Isolation High High Containment Pressure ;
- High Steam Flow Coincident With Safety Injection Coincident With Low Low T_{avg};
- High High Steam Flow Coincident With Safety Injection; and
- Low Low SG Water Level.

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-three configuration that satisfies redundancy requirements.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

BASES

ACTIONS

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

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 4 hours allowed for testing, are justified in Reference 5.

E.1.1, E.1.2, E.2.1, and E.2.2

Condition E applies to CS High High Containment Pressure which is a one-out-of-two channels, three-out-of-three sets logic. Condition E addresses the situation where containment pressure channels are inoperable. With channel(s) tripped, one or more of the three sets may be actuated.

Restoring the channel to OPERABLE status, or placing the other inoperable channel in the trip condition and verifying one channel in each pair remains OPERABLE within 6 hours, is sufficient to assure that the Function remains OPERABLE. The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel(s) to OPERABLE status, or place it in the tripped condition within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours. The allowed

BASES

ACTIONS

E.1.1, E.1.2, E.2.1, and E.2.2 (continued)

Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, this Function is a no longer required OPERABLE.

The Required Actions are modified by a Note that allows one channel to be bypassed for up to 4 hours for surveillance testing. Placing a channel in the bypass condition for up to 4 hours for testing purposes is acceptable based on the results of Reference 5.

F.1, F.2.1, and F.2.2

Condition F applies to Manual Initiation of Steam Line Isolation. If a train or channel is inoperable, 48 hours are allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of this Function and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

BASES

ACTIONS (continued)

G.1, G.2.1, and G.2.2

Condition G applies to the automatic actuation relay logic for the Steam Line Isolation and Feedwater Isolation Functions. The action addresses the train orientation of the ESF relay logic for these functions. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the actuation function. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the Functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 5) assumption that 8 hours is the average time required to perform relay logic train surveillance.

H.1 and H.2

Condition H applies to High High SG Water Level.

If one channel is inoperable, 6 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation.

BASES

ACTIONS

H.1 and H.2 (continued)

The 6 hour Completion Time is justified in Reference 5. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit to be placed in MODE 3 within the following 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, this Function is no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 6 hours allowed to place the inoperable channel in the tripped condition, and the 4 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 5.

I.1 and I.2

Condition I applies to Undervoltage on Buses 11 and 12 (21 and 22).

If one or both channel(s) on one bus is inoperable, 6 hours are allowed to restore the channel(s) to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two channels on the other bus will result in actuation. The 6 hour Completion Time is justified in Reference 5. Failure to restore the inoperable channel(s) to OPERABLE status or place it in the tripped

BASES

ACTIONS

I.1 and I.2 (continued)

condition within 6 hours requires the unit to be placed in MODE 3 within the following 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, this Function is no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 6 hours allowed to place the inoperable channel in the tripped condition, and the 4 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 5.

J.1 and K.1

Conditions J and K apply to the AFW automatic actuation relay logic function and to the AFW pump start on trip of both MFW pumps function.

The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a logic train or channel is inoperable, the applicable Condition(s) and Required Action(s) of LCO 3.7.5, “Auxiliary Feedwater (AFW) System,” are entered for the associated AFW Train or pump.

Required Action J.1 is modified by a note that allows placing a train in the bypass condition for up to 8 hours for surveillance testing provided the other train is OPERABLE. This is necessary to allow testing reactor trip system logic which is in the same cabinet with AFW logic. This is acceptable since the other AFW system train is OPERABLE and the probability for an event requiring AFW during this time is low.

BASES (continued)

SURVEILLANCE REQUIREMENTS

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

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of reactor protection analog system supplies both trains of the ESFAS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.2.1

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

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The ESF relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the test condition, thus preventing inadvertent actuation. All possible logic combinations are tested for each ESFAS function. The test includes actuation of master and slave relays whose contact outputs remain within the relay logic. The test condition inhibits actuation of the master and slave relays whose contact outputs provide direct ESF equipment actuation. Where the relays are not actuated, the test circuitry provides a continuity check of the relay coil. This verifies that the logic is OPERABLE and that there is a signal path to the output relay coils.

Functions which do not test the master and slave relays with the logic specify separate master and slave relay tests in Table 3.3.2-1.

The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.3

SR 3.3.2.3 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1. A successful test of the required contact(s) of a channel (logic input) relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The difference between the current “as-found” values and the previous test “as-left” values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The “as-found” and “as-left” values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 5) when applicable.

The Frequency of 92 days is justified in Reference 5.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a TADOT. This SR is a check of the following ESFAS Instrumentation Functions:

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.4 (continued)

1. CS Manual Initiation;

2. CI Manual Initiation;

3. Manual isolation of the steam lines;

4. AFW pump start on Undervoltage on Buses 11 and 12 (21 and 22); and

5. AFW pump start on trip of both MFW pumps.

This SR is performed every 24 months. A successful test of the required contact(s) of a channel (logic input) relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions, except the undervoltage start of the AFW pumps, have no associated setpoints. For the undervoltage start of the AFW pumps, setpoint verification is covered by other SRs.

SR 3.3.2.5

This SR is the performance of a TADOT to check the Safety Injection Manual Initiation Function. It is performed every 24 months on a STAGGERED TEST BASIS. The Frequency is adequate, based on industry operating experience and is consistent with a typical refueling cycle.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.5 (continued)

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

SR 3.3.2.6

SR 3.3.2.6 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. The difference between the current "as-found" values and the previous test "as-left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation. This test is performed every 24 months.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. This test is performed every 24 months.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 15, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. USAR, Section 7.

3. USAR, Section 14.

4. "Engineering Manual Section 3.3.4.1, Engineering Design Standard for Instrument Setpoint/Uncertainty Calculations".

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

B 3.3 INSTRUMENTATION

B 3.3.3 Event Monitoring (EM) Instrumentation

BASES

BACKGROUND

The primary purpose of the EM instrumentation is to display unit variables that provide information required by the control room operators during accident situations.

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by the USAR (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737.

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A and Category I variables.

Type A variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

Category I variables are the key variables deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions;

BASES

BACKGROUND (continued)

- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and

- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from Reference 2.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The EM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);

- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;

- Determine whether systems important to safety are performing their intended functions;

- Determine the likelihood of a gross breach of the barriers to radioactivity release;

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine if a gross breach of a barrier has occurred; and

- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

EM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category I, non-Type A, instrumentation is included in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk and satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The EM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A instrument variables, which provide information required by the control room operators to perform certain manual actions specified in the Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the EM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

BASES

LCO (continued)

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

An exception to the two channel requirement is Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Table 3.3.3-1 lists all Type A and Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER, as identified in Reference 3.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1, 2. <u>Power Range and Source Range Neutron Flux (Logarithmic Scale)</u>

Power Range and Source Range Neutron Flux (Logarithmic Scale) indication is provided to verify reactor shutdown. The two ranges are necessary to cover the full range of flux that may occur post accident.

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

BASES

LCO (continued)

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures

RCS Hot and Cold Leg Temperatures are Category I variables provided for verification of core cooling and long term surveillance.

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS. RCS hot and cold leg temperature is also used for unit stabilization and cooldown control.

The channels provide indication over a range of 50°F to 700°F.

5. Reactor Coolant System (RCS) Pressure (Wide Range)

RCS wide range pressure is a Category I variable provided for verification of core cooling and RCS integrity long term surveillance.

RCS pressure is used to verify when there should be SI flow to RCS from at least one train, when the RCS pressure is below the pump shutoff head.

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;

BASES

LCO

5. Reactor Coolant System Pressure (RCS) (Wide Range) (continued)

- to determine when to reset SI and shut off RHR;
- to determine when to manually restart Emergency Core Cooling System (ECCS) Pumps;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

RCS pressure is a Category I, Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

BASES

LCO (continued)

6. Reactor Vessel Water Level

Reactor Vessel Water Level is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

The Reactor Vessel Water Level Monitoring System provides a direct measurement of the collapsed liquid level above the bottom of the vessel. The collapsed level represents the amount of liquid mass that is in the reactor vessel. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

7. Containment Sump Water Level (Wide Range)

Containment Sump Water Level is provided for verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used for accident diagnosis and to determine when to begin the recirculation procedure.

8. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is provided for verification of RCS and containment OPERABILITY.

9. Penetration Flow Path Automatic Containment Isolation Valve (CIV) Position

CIV Position is provided for verification of Containment OPERABILITY and containment isolation.

When used to verify containment isolation, the important information is the isolation status of the containment

BASES

LCO

9. Penetration Flow Path Automatic Containment Isolation Valve (CIV) Position (continued)

penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two active valves. The position indication in the control room requirement is satisfied by the individual valve position indication lights (red or green), Containment Isolation panel 44104 (44515) white status lights, or the Safety Parameter Display System (SPDS) computer display. For containment penetrations with only one active CIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. Each penetration is treated separately and each penetration flow path is considered a separate Function. Therefore, separate Condition entry is allowed for each penetration flow path.

10. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to

BASES

LCO

10. Containment Area Radiation (High Range) (continued)

invoke site emergency plans. Containment radiation level is used to determine if a LOCA with core damage has occurred.

11. Not Used

12. Pressurizer Level

Pressurizer Level is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

13. Steam Generator Water Level (Wide Range)

SG Water Level is provided to monitor operation of decay heat removal via the SGs. A Category I indication of SG level is the wide range level instrumentation. The wide range level covers a span of 0% to 100% between the lower tubesheet and the separator.

The LCO requires two channels of indication in the control room to be OPERABLE for each SG (Wide Range). Each SG is treated separately and each SG indication is considered a separate function. Therefore, separate Condition entry is allowed for each SG indication.

SG Water Level (Wide Range) is used to:

BASES

LCO

13. Steam Generator Water Level (Wide Range) (continued)

- verify that the intact SGs are an adequate heat sink for the reactor;

- determine the nature of the accident in progress (e.g., verify an SGTR); and

- verify unit conditions for termination of SI.

Operator action is based on the control room indication of SG level. Wide range level is a Type A variable because the operator must manually raise and control SG level to ensure decay heat removal.

14. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CSTs provide a nonsafety grade water supply for the AFW System. The CSTs consist of three 150,000 gallon tanks connected to both units by a common outlet header. Inventory is monitored by a 0% to 100% level indication. CST Level is displayed on a control room indicator and unit computer. In addition, a control room annunciator alarms on low level.

CST Level is considered a Type D variable.

The DBAs that require AFW are the steam line break (SLB) and LOCA.

Reference Technical Specification Bases 3.7.6, "Condensate Storage Tanks" for additional information.

BASES

LCO (continued)

15. Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

An evaluation was made of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and trend the ensuing core heatup. Adequate core cooling monitoring is ensured with four valid CETs per quadrant (Ref. 3). Core Exit Temperature is used to determine RCS subcooling margin. RCS subcooling margin will allow termination of safety injection (SI), if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.

In accordance with Reference 3, due to the size of the reactor core, four thermocouples OPERABLE in the center region of the core and at least one thermocouple in each quadrant of the outside core region are needed to provide radial temperature gradient monitoring. The center core region is defined by the following CETs and their locations.

BASES

LCO

15. Core Exit Temperature (continued)

CET Number	CET Location
9	D-5
10	D-7
12	E-4
13	E-6
14	E-10
16	F-7
18	G-4
19	G-6
22	H-5
23	H-9
28	I-4
29	I-8
30	I-10
32	J-6
33	J-8
34	J-9

These required thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient.

16. Refueling Water Storage Tank (RWST) Level

The RWST Level is a Category I, Type A variable provided for verifying a water source to the ECCS and Containment Spray, determining the time for initiation of recirculation following a LOCA, and event diagnosis.

BASES

17. Steam Generator Water Level (Narrow Range)

Steam Generator Narrow Range level instrumentation is categorized as a Category I, Type A, variable provided as the primary indication used to identify the ruptured Steam Generator to preclude overfill in a Steam Generator Tube Rupture event. This instrumentation is qualified to provide indication during SGTR conditions and may not be available during other design bases events in which a harsh containment environment exists.

The LCO requires two channels of indication in the control room to be OPERABLE for each SG (Narrow Range). Each SG is treated separately, and each SG indication is considered a separate function. Therefore, separate Condition entry is allowed for each SG indication.

APPLICABILITY

The EM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. In MODES 3, 4, 5, and 6, unit conditions are such that the likelihood of an event that would require EM instrumentation is low; therefore, the EM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies when one or more Functions have one required

BASES

ACTIONS (continued)

channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, 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 EM instrumentation during this interval.

A Note has been added stating that Condition A is not applicable to the CETs. The CETs are controlled under Conditions B, E, and F.

B.1

Condition B applies when there is one or more required CET channel(s) inoperable and with at least 4 CETs OPERABLE in the center region of the core, and at least one CET OPERABLE in each quadrant of the outside core region. Required Action B.1 requires restoring the required CET channel(s) to OPERABLE status within 30 days. The 30 day Completion Time is acceptable based on operating experience and takes into account the remaining OPERABLE CETs, and the low probability of an event requiring EM Instrumentation during this interval.

C.1

Condition C applies when the Required Action and associated Completion Time for Condition A or B are not met. This Required Action specifies initiation of actions in Specification 5.6.8, a written report to be submitted to the NRC immediately. 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 unit conditions that would require information provided by this instrumentation.

BASES

ACTIONS (continued)

D.1

Condition D applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Required Action D.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring EM 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 EM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the EM Function will be in a degraded condition should an accident occur. Condition D is modified by a Note that CET channel(s).

BASES

ACTIONS (continued)

E.1

Condition E applies when three or more required CET channels are inoperable in one or more quadrants and less than four CET channels are OPERABLE in the center region of the core. Required Action E.1 requires restoring the required inoperable channels to OPERABLE status within 7 days. The 7 day Completion Time is acceptable based on operating experience and taking into account the remaining CETs and the low probability of an event occurring that would require the CETs to assess the reactor core.

F.1

Condition F applies when three or more required CET channels are inoperable in one or more quadrants and less than one CET channel OPERABLE in each quadrant of the outside core region. Required Action F.1 requires restoring the required inoperable channels to OPERABLE status within 7 days. The 7 day Completion Time is acceptable based on operating experience taking into account the remaining CETs and the low probability of an event occurring that would require the CETs to assess the reactor core.

G.1

Condition G applies when the Required Action and associated Completion Time of Condition D, E, or F are not met. Required Action G.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition D, E, or F and the associated Completion Time has expired, Condition G is entered for that channel and provides for transfer to the appropriate subsequent Condition.

BASES

ACTIONS (continued)

H.1

If the Required Action and associated Completion Time of Condition G is not met and Table 3.3.3-1 directs entry into Condition H, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, to reach the required unit condition from full power conditions in an orderly manner and without challenging unit systems.

I.1

Alternate means (e.g., CETs) of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed and tested. These alternate means may be temporarily installed if the normal EM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed EM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal EM channels.

BASES (continued)

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each EM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors.

The Frequency is based on operating experience and consistency with the typical PI refueling cycle.

REFERENCES

1. USAR Section 7.10.

2. Regulatory Guide 1.97, Revision 2.

3. NRC approved LAR 121 dated November 9, 1995.

B 3.3 INSTRUMENTATION

B 3.3.4 4 kV Safeguards Bus Voltage Instrumentation

BASES

BACKGROUND

The Diesel Generators (DGs) provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Redundant offsite power sources ensure an available source of offsite power to the Engineered Safety Features when one offsite path becomes unavailable. Undervoltage protection, via load sequencers, will provide voltage and load restoration, including DG start if an undervoltage (UV) or degraded voltage (DV) condition occurs at the 4 kV safeguards buses. There are two trains of load sequencers and UV and DV signals, one train for each 4 kV safeguards bus. These features are described in the USAR (Ref. 1).

Eight voltage relays provide input to the load sequencer for each 4 kV safeguards bus for detecting a sustained DV, approximately 95% of 4160V, or a UV, approximately 75% of 4160V, condition. Four relays are paired in the load sequencer logic in a two-out-of-two channel logic whose output is combined into a one-out-of-two times logic for each function, DV and UV. Time delays are applied within the UV and DV functions to prevent actuation during normal transients. A DG start time delay is also provided in the DV function to allow the condition to be corrected by external actions within a time period that will not cause damage to operating equipment.

The load sequencer provides a DG start signal from the UV function if neither offsite path is available. The DV function provides a DG start signal and transfers the bus from the grid to the DG. Load rejection and load restoration sequencing is actuated by an SI signal input, or when the bus is being automatically transferred. The load sequencer is considered to be a support system to the associated DG. An inoperable load sequencer would not allow the associated DG to

BASES

BACKGROUND (continued)

automatically start, connect to the bus, and provide load reception. However, when a load sequencer is inoperable, the associated DG can still be manually started and loaded.

Allowable Values and Trip Setpoints

The trip setpoints used in the relays are based on the plant specific voltage analysis discussed in the USAR (Ref. 1).

The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for protective action to ensure that the consequences of Design Basis Accidents (DBA's), in coincidence with offsite power unavailability or instability, will be acceptable. The Allowable Value is considered a limiting value such that a channel is OPERABLE if the measured setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to within the established calibration tolerance band of the trip setpoint in accordance with the uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria).

Setpoints adjusted consistent with the requirements of the Allowable Values provide a conservative margin with regard to instrument uncertainties to ensure that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values are specified as applicable for each Function in SR 3.3.4.3. Trip setpoints are also specified in the unit specific setpoint calculations. The specified trip setpoints are selected to

BASES

BACKGROUND

Allowable Values and Trip Setpoints (continued)

ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the relay is performing as required. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE. Operation with a measured setpoint less conservative than the specified trip setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation. Each Allowable Value specified is conservative with respect to the values assumed in the analyses described in Reference 1 in order to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in Reference 2.

APPLICABLE SAFETY ANALYSES

The 4 kV safeguards bus voltage instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a small break loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required 4 kV safeguards bus voltage instrumentation, in conjunction with the ESF systems powered from the DGs, provide

BASES

APPLICABLE SAFETY ANALYSES (continued)

unit protection in the event of any of the analyzed accidents discussed in Reference 3, in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable.

The 4 kV safeguards bus voltage instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for 4 kV safeguards bus voltage instrumentation requires that four channels per bus of both the UV and DV Functions, and one automatic load sequencer per bus, shall be OPERABLE in MODES 1, 2, 3, and 4. In MODES 5 and 6, the four channels and the associated load sequencer must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. A UV or DV channel is OPERABLE when it is capable of actuating the load sequencer. Loss of the 4 kV Safeguards Bus Voltage Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents.

A channel is OPERABLE with a trip setpoint outside its calibration tolerance band provided the trip setpoint “as-found” value does not exceed its associated Allowable Value and provided the trip setpoint “as-left” value is adjusted to within the calibration tolerance band.

APPLICABILITY

The 4 kV Safeguards Bus Voltage Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an UV or degraded power to the safeguards bus.

BASES (continued)

ACTIONS

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the 4 kV safeguards bus voltage Function with one UV or one DV or both (one UV and one DV) channel(s) per bus inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in bypass within 6 hours. With a channel in bypass, the remaining 4 kV safeguards bus voltage instrumentation channels provide UV or DV Function, two-out-of-two logic, initiation.

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

Condition A has been modified by a Note indicating that this Condition is only applicable to Functions a and b.

BASES

ACTIONS (continued)

B.1 and B.2

Condition B applies when one or more Functions with two channels per bus inoperable.

Required Action B.1 requires placing one channel in bypass and the other inoperable channel in trip. Required Action B.2 requires the verification that all channels associated with the redundant load sequencer are OPERABLE. The 6 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring a DG start occurring during this interval.

Condition B has been modified by a Note indicating that this Condition is only applicable to Functions a and b.

C.1

Condition C applies in MODE 1, 2, 3, or 4 when Required Action and associated Completion Time of Condition A or B are not met, when Functions a or b or both with three channels per bus inoperable, or when one required load sequencer is inoperable.

Required Action C.1 requires the performance of SR 3.3.4.2 for the OPERABLE automatic load sequencer. The 6 hour Completion Time provides a reasonable time for performance of the SR. Performance of this SR on a more frequent basis, once per 24 hours thereafter, ensures that the OPERABLE load sequencer remains OPERABLE while in this Condition. If the redundant train load sequencer fails to pass the SR it is inoperable and Condition D must then be entered.

BASES

ACTIONS (continued)

C.2 and C.3

To ensure a highly reliable power source remains with an inoperable load sequencer, the offsite paths for the associated 4 kV safeguards bus must be capable of accepting the block loading that could result from an SI signal and availability must be verified on a more frequent basis. The 8 hour Completion Time is consistent with the Completion Time for an inoperable 4 kV safeguards bus, as required in LCO 3.8.9, “Distribution Systems - Operating.” The verification of the operability of the offsite paths for associated 4 kV safeguards on a more frequent basis, once per 8 hours thereafter, ensures that the OPERABLE paths remain OPERABLE while in this Condition.

An inoperable load sequencer results in associated DG unavailability for automatic start, connection to the bus and load reception. In Condition C, the remaining OPERABLE DG and offsite paths are adequate to supply electrical power to the onsite Safeguards AC Distribution System.

Offsite power block loading capability is established by administrative control of selected distribution system loads to reduce potential starting current.

C.4

Required Action C.4 is intended to provide assurance that a loss of offsite power, during the period that a load sequencer is inoperable and the associated DG is inoperable for automatic start, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

BASES

ACTIONS

C.4 (continued)

The Completion Time for Required Action C.4 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and paths are adequate to supply electrical power to the onsite Safeguards Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost;

BASES

ACTIONS

C.4 (continued)

however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.5

Required Action C.5 requires that the automatic load sequencer be restored to OPERABLE status. The 7 day Completion Time allows a reasonable time to repair the inoperable load sequencer. The Completion Time is consistent with the Completion Time to restore an inoperable DG, as required in LCO 3.8.1, “AC Sources - Operating.”

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C are not met. The unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours.

E.1

Required Action E.1 requires that LCO 3.8.2 “AC Sources-Shutdown” Condition(s) and Required Action(s) for the DG made inoperable from inoperable 4 kV safeguards bus voltage

BASES

ACTIONS

E.1 (continued)

instrumentation be entered immediately when Required Action and Completion Time of Condition A or B are not met, or Functions a and b or both with three channels per bus inoperable, or when one required automatic load sequencer is inoperable in MODE 5 or 6. The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 is the performance of a COT every 31 days.
A COT is performed on each required undervoltage and degraded voltage relay channel to ensure they will perform the intended function. For these tests, the relay trip setpoints are verified and adjusted as necessary. The Frequency is based on the known reliability of the relays and load sequencers and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.4.2

SR 3.3.4.2 is the performance of an ACTUATION LOGIC TEST on each required load sequencer every 31 days.

The test verifies that the logic functions provided by the load sequencer for voltage and load restoration are OPERABLE. The Frequency is based on the known reliability of the load sequencers and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.3

SR 3.3.4.3 is the performance of a CHANNEL CALIBRATION on the undervoltage and degraded voltage channels.

The setpoints, as well as the response to a UV and a DV test, shall include a single point verification that an actuation occurs within the required time delay, as shown in Reference 1.

The first degraded voltage time delay of 8 ± 0.5 seconds has been shown by testing and analysis to be long enough to allow for normal transients (i.e., motor starting and fault clearing). It is also longer than the time required to start the safety injection pump at minimum voltage. Following this delay, an alarm in the control room alerts the operator to the degraded condition. The subsequent occurrence of a safety injection actuation signal would immediately separate the affected bus or buses from the offsite power system. The degraded voltage DG start time delay range of 7.5 to 63 seconds is a limited duration such that the permanently connected Class 1E loads will not be damaged. Following this delay, if the operator has failed to restore adequate voltages, the affected bus or buses would be automatically separated from the offsite power system. The second time delay is specified here as an allowable range to be longer than the first time delay and shorter than the time which could cause damage to the permanently connected Class 1E loads.

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the voltage relay channel. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.3 (continued)

The Frequency of 24 months is based on operating experience and consistency with the typical PI refueling cycle and is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. USAR, Section 8.4.
2. "Engineering Manual Section 3.3.4.1, Engineering Design Standard for Instrument Setpoint/Uncertainty Calculations".
3. USAR, Section 14.

B 3.3 INSTRUMENTATION

B 3.3.5 Not Used

B 3.3 INSTRUMENTATION

B 3.3.6 Control Room Special Ventilation System (CRSVS) Actuation Instrumentation

BASES

BACKGROUND

The CRSVS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the Control Room Ventilation System provides control room ventilation. Upon receipt of an actuation signal, automatic control dampers of the associated train isolate the control room and direct a portion of recirculated air through redundant PAC filters before entry to the air handling units. This system is described in the Bases for LCO 3.7.10, "Control Room Special Ventilation System."

The actuation instrumentation consists of radiation monitors in the control room area. A high radiation signal from these detectors will initiate the associated train of the CRSVS. The CRSVS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CRSVS acts to terminate the supply of unfiltered outside air to the control room and initiate filtration. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, the radiation monitor actuation of the CRSVS is a backup for the SI signal actuation. This ensures

BASES

APPLICABLE SAFETY ANALYSES (continued)

initiation of the CRSVS during a loss of coolant accident or steam generator tube rupture.

The radiation monitor actuation of the CRSVS during movement of irradiated fuel assemblies is the primary means to ensure control room habitability in the event of a fuel handling accident.

The CRSVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CRSVS is OPERABLE.

1. Manual Initiation

   The LCO requires two channels OPERABLE. The operator can initiate the CRSVS at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

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

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

2. Control Room Radiation

   The LCO specifies two required Control Room Atmosphere Radiation Monitors, R23 and R24, to ensure that the radiation monitoring instrumentation necessary to initiate the CRSVS remains OPERABLE.

BASES

LCO

2. Control Room Radiation (continued)

A high radiation signal from one control room radiation monitor channel (R23 or R24) initiates the following:

a. The Cleanup Fan on the associated train starts;

b. Exhaust Dampers on the associated train are isolated; and

c. Outside Air Dampers for both trains are isolated.

Table 3.3.6-1 specifies the allowable value for the Control Room Atmosphere Radiation Monitors as five times background. No Analytical Limit is assumed in the accident analysis for this function. This allowable value was developed outside the PI setpoint methodology.

3. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

CRSVS Function 1 in Table 3.3.6-1 must be OPERABLE in MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies.

The Applicability for CRSVS actuation on ESFAS Safety Injection Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Safety Injection Function Applicability.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this

BASES

ACTIONS (continued)

Specification may be entered independently for each Function listed in Table 3.3.6-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

If one or more Functions has one channel inoperable, place one CRSVS train in operation with the opposite train outside air damper closed within 7 days. With one manual switch inoperable either train of CRSVS may be placed in operation. If one radiation monitoring channel is inoperable, the associated CRSVS train must be placed in operation and the outside air dampers associated with the opposite CRSVS train must be closed. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

B.1 and B.2

Condition B applies when one or more Functions with two channels inoperable. The first Required Action is to immediately enter the applicable Conditions and Required Actions of LCO 3.7.10 for two CRSVS trains made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

Alternatively, both trains may be placed in operation with the outside air dampers closed. This ensures the CRSVS function is performed even in the presence of a single failure.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require CRSVS actuation.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which CRSVS Actuation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. A

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1 (continued)

CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

The Frequency is based on operating experience that demonstrates channel failure is rare.

SR 3.3.6.2

A COT is performed once every 92 days on each required channel to ensure the entire channel, including the actuation devices, will perform the intended function. This test verifies the capability of the instrumentation to provide the CRSVS actuation. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The setpoints are left consistent with the unit specific calibration procedure tolerance. The Frequency is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.3 (continued)

The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

SR 3.3.6.4

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is consistent with the typical industry refueling cycle.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow - Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with both pumps running. The minimum RCS flow limit specified in the COLR corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criteria. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit and RCS average temperature limit specified in the COLR are based on transient analyses assumptions, with allowance for steady state fluctuation, deadband and measurement errors. The measured RCS flow rate is decreased by appropriate uncertainties when being compared to the limits specified in the COLR. The limits in this section may be from DNB limiting or non-DNB limiting accident analyses per WCAP-14483-A, "Generic Methodology for Expanded Core Operating Limits Reports."

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables-pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

BASES

LCO (continued)

The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location and have been adjusted for instrument error.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp > 5% RTP per minute or a THERMAL POWER step > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Since increasing power transients are initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations. Decreasing power transients are in the direction which provides increased DNBR margin.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action.

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

BASES

ACTIONS

A.1 (continued)

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

BASES

REQUIREMENTS
(continued)

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

Measurement of RCS total flow rate once every 24 months allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate as established by the COLR.

The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

This SR is modified by Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is required to be performed within 72 hours after reaching 90% RTP. This exception is appropriate since power ascension must be allowed for the flow measurement to be performed at a power level representative of rated power operations and some time is allowed to perform the test.

REFERENCES

1. USAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is isothermal temperature coefficient (ITC), LCO 3.1.3, "Isothermal Temperature Coefficient (ITC)." In the transient and accident analyses, the ITC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the RCS water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen for critically.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

BASES (continued)

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures are within the nominal operating envelope around the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 7°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the ITC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

BASES (continued)

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the ITC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$,which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $k_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $k_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 540°F every 12 hours. The SR to verify RCS loop average temperatures every 12 hours takes into account indications and alarms that are continuously available to the operator in the control

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

room and are consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.

REFERENCES

1. USAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature, based on Reference 1.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G, requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials and requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G.

BASES

BACKGROUND (continued)

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material has been established by periodically removing and evaluating irradiated reactor vessel material specimens, in accordance with ASTM E 185, July 1982, and Appendix H of 10 CFR 50. The operating P/T limit curves have been adjusted based on the evaluation findings and the recommendations of the program prescribed in Reference 2.

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, “RCS Minimum Temperature for Criticality.”

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must

BASES

BACKGROUND (continued)	be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E, provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.
APPLICABLE SAFETY ANALYSES	The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition. RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The two elements of this LCO are: a. The limit curves for heatup, cooldown, and ISLH testing; and b. Limits on the rate of change of temperature. The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure. The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

BASES

LCO (continued)

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G. Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, “RCS Pressure, Temperature, and Flow - Departure from Nucleate Boiling (DNB) Limits”; LCO 3.4.2, “RCS Minimum Temperature for Criticality”; and Safety Limit 2.1, “Safety Limits,” also provide operational restrictions for pressure and temperature. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

BASES (continued)

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including an engineering evaluation to determine effects of the out-of-limit condition on the structural integrity of the RCS, a comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E, may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring that Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

ACTIONS (continued)

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure conditions, which requires reduced temperature, the possibility of propagation of undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that

BASES

ACTIONS

C.1 and C.2 (continued)

the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E, may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring that Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. WCAP-14040-NP-A, January 1996.

2. USAR, Section 4.7.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid; and

d. Providing a second barrier against fission product release to the environment.

The reactor coolant is circulated through two loops connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant

BASES

APPLICABLE SAFETY ANALYSES (continued)

forced flow rate, which is represented by the number of RCS loops in service.

Both transient and steady state analyses include the effect of flow on the departure from nucleate boiling ratio (DNBR). The transient and accident analyses for the plant have been performed assuming both RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the two pump coastdown, single pump locked rotor, and rod withdrawal events (Ref. 1).

The plant is designed to operate with both RCS loops in operation to maintain DNBR within limits during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, two pumps are required at power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the

BASES

APPLICABILITY (continued)

assumptions of the accident analyses remain valid, both RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, “RCS Loops-MODE 3”;
LCO 3.4.6, “RCS Loops-MODE 4”;
LCO 3.4.7, “RCS Loops-MODE 5, Loops Filled”;
LCO 3.4.8, “RCS Loops-MODE 5, Loops Not Filled”;
LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation-High Water Level” (MODE 6); and
LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level” (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE

SR 3.4.4.1

BASES (continued)

REQUIREMENTS

This SR requires verification every 12 hours that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. USAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops - MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the RCS is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through two RCS loops, connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are normally used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat in response to transients or operational events. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

The MODE 3 decay heat removal requirements are low enough that natural circulation is sufficient to remove core decay heat when the potential for operational events is minimized (Ref. 1).

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting

BASES

APPLICABLE SAFETY ANALYSES (continued)

in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In MODE 3 with the Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and two RCS loops are required to be OPERABLE and in operation to ensure that the accident analyses input assumptions are met.

Failure to provide decay heat removal by forced circulation, when control rods may be withdrawn, may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops - MODE 3 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that both RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, both RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with the Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the transient analysis acceptance criteria will be met.

When the Rod Control System is not capable of rod withdrawal, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure redundant capability for decay heat removal.

BASES

LCO (continued)

The Note permits both RCPs to be de-energized for ≤ 12 hours to perform preplanned work activities.

One purpose of the Note is to allow performance of tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test was performed during the initial startup testing program, and would normally only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. Another test performed during the startup testing program was the validation of rod drop times, both with and without flow.

The MODE 3 decay heat removal requirements are low enough that natural circulation is sufficient to remove core decay heat when the potential for operational events is minimized (Ref. 1).

Any future no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping the pumps in order to perform this test and validate the assumed analysis values.

Another purpose of the Note is to allow stopping of both RCP's for a sufficient time to perform station electrical lineup changes without transition to MODE 4. During these evolutions both RCP's may be inoperable. Transition to MODE 4 would put the plant through unnecessary cooldown and heatup transients. The 12 hour time period specified is adequate to perform the necessary load shedding, switching and load restoration activities and restart an RCP without requiring transition to MODE 4.

Utilization of the Note is permitted provided the following conditions are met:

BASES

LCO (continued)

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentration less than required to meet SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited to preclude the need for a boration, due to the time required to achieve a uniform distribution when in natural circulation (Ref. 1); and

b. Core outlet temperature is maintained at least 10ºF below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG which is capable of removing decay heat as specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to Mode 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4, “RCS Loops-MODES 1 and 2”;
LCO 3.4.6, “RCS Loops-MODE 4”;
LCO 3.4.7, “RCS Loops-MODE 5, Loops Filled”;
LCO 3.4.8, “RCS Loops-MODE 5, Loops Not Filled”;

APPLICABILITY

LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant

BASES

(continued)

Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level"(MODE 6).

ACTIONS

A.1

If one RCS loop is inoperable, redundancy for forced circulation heat removal is lost. The Required Action is restoration of the RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

If power is lost to both RCPs, the unit can be stabilized in natural circulation for 72 hours while the RCS loops are restored to OPERABLE status. Natural circulation operation of the RCS, in combination with Required Actions D.1 and D.2, will provide sufficient decay heat removal and RCS mixing in MODE 3 to assure continued core cooling.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

If one RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the RCS loop to operation or place the Rod Control System in a condition incapable of rod withdrawal (e.g., to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets). When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be rendered incapable of rod withdrawal. The Completion Times of 1 hour to restore the required RCS loop to operation or defeat the Rod Control System is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If both RCS loops are inoperable or a required RCS loop is not in operation, except during conditions permitted by the Note in the LCO section, the Rod Control System must be placed in a condition incapable of rod withdrawal (e.g., all CRDM's de-energized by opening the RTBs or de-energizing the MG sets). All operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

coolant could be introduced to the core; however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification that the SG has the capability to remove decay heat. The ability to remove decay heat requires the ability to pressurize and control pressure in the RCS, sufficient secondary side water level in the SG relied on for decay heat removal, and an available supply of feedwater (Ref. 2). The ability of the SG to provide an adequate heat sink for decay heat removal further ensures that the SG tubes remain covered.

The 12 hour Frequency is considered adequate in view of the other indications available in the control room to alert the operator to a loss of the SG to remove decay heat.

SURVEILLANCE

SR 3.4.5.3

BASES

SURVEILLANCE REQUIREMENTS (continued)

Verification that each required RCP is OPERABLE ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to each required RCP. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a pump is not in operation.

REFERENCES

1. License Amendment Request Dated November 19, 1999. (Approved by License Amendment 152/143, July 14, 2000.)

2. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through two RCS loops connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs or RHR pumps circulate the coolant through the reactor vessel and SGs or the RHR heat exchangers at a sufficient rate to ensure proper heat transfer and boric acid mixing.

In MODE 4, either RCPs or RHR pumps can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCS loop or one RHR loop for decay heat removal and transport. The flow provided by one RCS loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation increases the time available for mitigation of an accidental boron dilution event. The RCS and RHR loops provide this circulation.

RCS Loops - MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be de-energized for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the LCO tests performed during the startup testing program was validation of rod drop times during cold conditions, both with and without flow. If changes are made to the RCS that would cause a change in flow characteristics of the RCS, the input values must be revalidated by conducting the test again. Use of this Note also permits any future no flow test to be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping the pumps in order to perform this test and validate the assumed analysis values. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentration less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM in maintained is prohibited to preclude the need for a boration, due to the time required to achieve a uniform distribution when in natural circulation (Ref. 1); and

BASES

LCO (continued)

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires a steam or gas bubble in the pressurizer or that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ the OPPS enable temperature specified in the PTLR. A steam or gas bubble ensures that the pressurizer will accommodate the swell resulting from an RCP start. Either of these restraints prevents a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG which is capable of removing decay heat as specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing.

Operation in other MODES is covered by:

LCO 3.4.4, “RCS Loops - MODES 1 and 2”;
LCO 3.4.5, “RCS Loops - MODE 3”;
LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled”;
LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled”;
LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level” (MODE 6); and

BASES

APPLICABILITY (continued)

LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If one required loop is inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal. Entry to a reduced MODE (MODE 5 or 6) requires RHR availability for long term decay heat removal. Remaining in MODE 4, with RCS loop operation, is conservative.

If restoration is not accomplished and an RHR Loop is OPERABLE, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 rather than MODE 4. The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

The Required Action is modified by a Note which indicates that the unit must be placed in MODE 5 only if a RHR loop is OPERABLE. With no RHR loop OPERABLE, the unit is in a condition with only limited cooldown capabilities. Therefore, the actions are to be concentrated on the restoration of a RHR loop, rather than a cooldown of extended duration.

BASES

ACTIONS (continued)

B.1 and B.2

If both loops are inoperable or a required loop not in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. The margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core; however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that the required RCS or RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification that the required SG has the capability to remove decay heat. The ability to remove decay heat requires the ability to pressurize and control pressure in the RCS, sufficient secondary side water level in the SG relied on for decay heat removal, and an available supply of feedwater (Ref. 2). The ability of the SG to provide an adequate heat sink for decay heat removal further ensures that the SG tubes remain covered. The 12 hour Frequency is considered adequate in view of the other indications available in the control room to alert the operator to a loss of capability of the SG to remove decay heat.

SR 3.4.6.3

Verification that each required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a pump is not in operation.

BASES (continued)

REFERENCES

1. License Amendment Request Dated November 19, 1999. (Approved by License Amendment 152/143, July 14, 2000.)

2. NRC Information Notice 95-35, “Degraded Ability of Steam Generator to Remove Decay Heat by Natural Circulation.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The RCS must be intact to support natural circulation. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another

BASES

BACKGROUND (continued)	OPERABLE RHR loop or maintaining a SG capable of removing decay heat to provide an alternate method for decay heat removal via natural circulation.
APPLICABLE SAFETY ANALYSES	In MODE 5, RCS circulation increases the time available for mitigation of an accidental boron dilution event. The RHR loops provide this circulation. RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The purpose of this LCO is to require that at least one RHR loop be OPERABLE and in operation with an additional RHR loop OPERABLE or a SG capable of removing decay heat via natural circulation. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to provide redundancy. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is a SG. Should the operating RHR loop fail, the SG could be used to remove decay heat via natural circulation. Note 1 permits all RHR pumps to be de-energized ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program was validation of rod drop times during cold conditions, both with and without flow. If changes are made to the RCS that would cause a change in flow characteristics of the RCS, the input values must be revalidated by conducting the test again. Any future no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping the pumps in order to perform this test and validate the assumed analysis values. The 1 hour time period is adequate to perform the test, and operating

BASES

LCO (continued)

experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentration less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited to preclude the need for a boration, due to the time required to achieve a uniform distribution when in natural circulation (Ref. 2); and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires a steam or gas bubble in the pressurizer or that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ the OPPS enable temperature specified in the PTLR. A steam or gas bubble ensures that the pressurizer will accommodate the swell resulting from an RCP start. Either of these restraints prevents a low temperature overpressure event due to a thermal transient when an RCP is started.

BASES

LCO (continued)	Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG is capable of removing decay heat via natural circulation when: 1) there is the ability to pressurize and control pressure in the RCS; 2) there is sufficient secondary side water level in the SG relied on for decay heat removal; and 3) there is an available supply of feedwater (Ref. 1). An OPERABLE SG can perform as a heat sink via natural circulation when it has the capability to remove decay heat as specified in SR 3.4.7.2.
APPLICABILITY	In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or a SG is capable of removing decay heat. Operation in other MODES is covered by: LCO 3.4.4, "RCS Loops-MODES 1 and 2"; LCO 3.4.5, "RCS Loops-MODE 3"; LCO 3.4.6, "RCS Loops-MODE 4"; LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled"; LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

BASES (continued)

ACTIONS

A.1, A.2, B.1 and B.2

If one RHR loop is OPERABLE and the SGs are not capable of removing decay heat, redundancy, for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG capability to remove decay heat. Either Required Action will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

C.1 and C.2

If a required RHR loop is not in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core; however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

SR 3.4.7.2 requires verification that the required SG has the capability to remove decay heat via natural circulation. This provides an alternate decay heat removal method in the event that the second RHR loop is not OPERABLE. The ability to remove decay heat requires the ability to pressurize and control pressure in the RCS, sufficient secondary side water level in the SG relied on for decay heat removal, and an available supply of feedwater (Ref. 1). The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of capability of the SG to remove decay heat.

SR 3.4.7.3

Verification that each required RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required RHR pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. If at least one SG is capable of decay heat removal, this Surveillance is not needed. The Frequency

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.3 (continued)

of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a pump is not in operation.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation".

2. License Amendment Request Dated November 19, 1999. (Approved by License Amendment 152/143, July 14, 2000.)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation increases the time available for mitigation of an accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops - MODE 5 (Loops Not Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation to transfer heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one operating RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to provide redundancy.

BASES

LCO (continued)

Note 1 permits all RHR pumps to be de-energized ≤ 1 hour per 8 hour period. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained > 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure SDM is maintained or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops-MODES 1 and 2";
LCO 3.4.5, "RCS Loops-MODE 3";
LCO 3.4.6, "RCS Loops-MODE 4";
LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

BASES (continued)

ACTIONS

A.1

If one required RHR loop is inoperable, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no required loop is OPERABLE or the required loop is not in operation, except during conditions permitted by Note 1, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. The margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core; however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

The Note in Required Action B.2 allows the use of one safety injection pump to provide heat removal in the event of a loss of RHR system cooling during reduced RCS inventory conditions.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that each required pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a pump is not in operation.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, “Pressurizer Safety Valves,” and LCO 3.4.11, “Pressurizer Power Operated Relief Valves (PORVs),” respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases are typically present in the RCS and can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control. These small amounts of noncondensible gases can be ignored if the steam bubble is present.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant.

BASES

BACKGROUND (continued)	Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat. One group of pressurizer heaters is adequate to maintain natural circulation conditions during a loss of offsite power. Two groups are required to be available to ensure redundant capability.
APPLICABLE SAFETY ANALYSES	In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting with respect to pressurizer parameters. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption,the analyses neglect the small fraction of noncondensible gases normally present. Safety analyses presented in the USAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure. The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737, is the reason for providing an LCO.

BASES

LCO (continued)

The LCO requirement for the pressurizer to be OPERABLE with ≤ 90% level ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The level limit is specified to agree with the high pressurizer level trip allowable value. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 100 kW, capable of being powered from an emergency power supply. These are Groups A and B. One group of pressurizer heaters with a capacity ≥ 100 kW is adequate to maintain natural circulation conditions during a loss of offsite power (Ref. 2). Two groups are required to be OPERABLE to ensure redundant capability.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling

BASES

APPLICABILITY (continued)

for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1, A.2, A.3, and A.4

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Allowable Value for Pressurizer High Water Level-Reactor Trip.

If the pressurizer water level is not within the limit, action must be taken to bring the unit to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3, with all rods fully inserted and incapable of withdrawal. Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

B.1

If one group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using normal station powered heaters.

BASES

ACTIONS (continued)

C.1 and C.2

If one group of pressurizer heaters is inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess level for any deviation. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 24 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

BASES

SURVEILLANCE REQUIRMENTS

SR 3.4.9.3 (continued)

This SR is not applicable for the Group A heaters since this group is permanently powered by a Class 1E power supply.

This Surveillance demonstrates that the Group B heaters can be manually transferred from the non-safeguards to the safeguards power supply and energized. The Frequency of 24 months is based on a typical fuel cycle and is consistent with similar verifications of emergency power supplies.

REFERENCES

1. USAR, Section 14.
2. USAR, Section 4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The required relief capacity for each valve, 325,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures ≤ the OPPS enable temperature specified in the PTLR, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, “Low Temperature Overpressure Protection (LTOP) > Safety Injection (SI) Pump Disable Temperature”, and LCO 3.4.13, “Low Temperature Overpressure Protection (LTOP) ≤ Safety Injection (SI) Pump Disable Temperature.”

BASES

BACKGROUND (continued)	The as left upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established. The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.
APPLICABLE SAFETY ANALYSES	All accident and safety analyses in the USAR (Ref. 2) that require safety valve actuation assume operation of both pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of both safety valves. Transients that could result in overpressurization if not properly terminated include: a. Uncontrolled rod withdrawal from power; b. Loss of reactor coolant flow; c. Loss of external electrical load; d. Loss of normal feedwater; e. Loss of all AC power to station auxiliaries; and f. Locked rotor.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Detailed analyses of the above transients are contained in Reference 2. Compliance with this LCO is consistent with the design bases and accident analyses assumptions. Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The two pressurizer safety valves are set to open at the RCS design pressure (2485 psig), within a ± 3% tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits following testing are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analyses being required prior to resumption of reactor operation.
APPLICABILITY	In MODES 1, 2, and 3, and portions of MODE 4 above the OPPS enable temperature, OPERABILITY of both valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection. The LCO is not applicable in MODE 4 when any RCS cold leg temperatures are ≤ the OPPS enable temperature specified in the

BASES

APPLICABILITY (continued)

PTLR or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 36 hour exception is based on 18 hour outage time for each of the two valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining RCS overpressure protection. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if both pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperatures ≤ the OPPS enable temperature specified in the PTLR within 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner

BASES

ACTIONS

B.1 and B.2 (continued)

and without challenging plant systems. With any RCS cold leg temperatures at or below the OPPS enable temperature specified in the PTLR, overpressure protection is provided by the LTOP function. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by both pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III, with the 1968 Winter Addendum.

2. USAR, Section 14.

3. WCAP-7769, Rev. 1, June 1972.

4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are air operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permits performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The PORVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. The PORVs and their associated block valves are powered from two separate safety trains.

BASES

BACKGROUND (continued)	The two PORVs each have a relief capacity of 179,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer High Pressure Reactor Trip setpoint following a step reduction of 40% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12 and LCO 3.4.13 for LTOP requirements.
APPLICABLE SAFETY ANALYSES	Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator. The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical (Ref. 1). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint; thus, the DNBR calculation is more conservative. As such, this actuation is not required to mitigate these events, and PORV automatic operation is, therefore, not an assumed safety function. Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized with the capability of being closed, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when conditions dictate closure of the block valve to limit leakage.

Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORVs are required to be OPERABLE for manual actuation to mitigate a SGTR. The PORV and its block valve are also required to be OPERABLE in MODES 1, 2, and 3 to maintain the integrity of the reactor coolant pressure boundary. This requires the ability to manually control the block valve to isolate a PORV with excessive seat leakage or a stuck-open PORV.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3 when RCS pressure is high and there is potential for a SGTR. The LCO is not applicable in

BASES

APPLICABILITY (continued)

MODES 4 and 5, and MODE 6 with the reactor vessel head in place, when both pressure and core energy are decreased and a SGTR can not occur. LCO 3.4.12 and LCO 3.4.13 address the PORV requirements in these MODES.

ACTIONS

A Note has been added to clarify that each pressurizer PORV and each block valve are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis) for Conditions A, B and C.

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

BASES

ACTIONS (continued)

B.1, B.2 and B.3

If one PORV is inoperable for reasons other than Condition A, and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on the small potential for challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of

BASES

ACTIONS

C.1 and C.2 (continued)

mitigating an event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 72 hours, the PORV may be restored to automatic operation. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

The Required Actions C.1 and C.2 are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then the plant must be brought to a MODE in which the LCO does not apply.

To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12 and LCO 3.4.13.

BASES

ACTIONS (continued)

E.1, E.2, E.3 and E.4

If both PORVs are inoperable for reasons other than Condition A and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12 and LCO 3.4.13.

F.1

If both block valves are inoperable, it is necessary to restore at least one block valve within 2 hours. The Completion Time is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation.

The Required Action F.1 is modified by a Note stating that the Required Action does not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

BASES

ACTIONS (continued)

G.1 and G.2

If the Required Actions of Condition F are not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12 and LCO 3.4.13.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The basis for the Frequency of 92 days is the ASME Code for Operation and Maintenance of Nuclear Power Plants.

This SR is modified by two Notes. Note 1 modifies this SR by stating that it is not required to be performed with the block valve closed in accordance with the Required Action of Condition B or E. Opening the block valve in this condition increases the risk of an unisolable leak from the RCS since the PORV is already inoperable.

Note 2 modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the test to be performed in MODE 3 under operating temperature and pressure conditions, prior to entering MODE 1 or 2.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.11.2 (continued) manually actuated for mitigation of an SGTR. The Frequency of 24 months is based on a typical refueling cycle and industry accepted practice. The Note modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the test to be performed in MODE 3 under operating temperature and pressure conditions prior to entering MODE 1 or 2.
REFERENCES	1. USAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) – Reactor Coolant System Cold Leg Temperature (RCSCLT) > Safety Injection (SI) Pump Disable Temperature

BASES

BACKGROUND

The LTOP function limits RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The Over Pressure Protection System (OPPS) and the pressurizer power operated relief valves (PORVs) provide the LTOP function (Ref. 2). The PTLR provides the maximum allowable OPPS actuation setpoints for the PORVs and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES. The LTOP MODES are the MODES as defined in the Applicability statement of LCO 3.4.12 and LCO 3.4.13.

The pressurizer safety valves and PORVs at their normal setpoints do not provide overpressure protection for certain low temperature operational transients. Inadvertent pressurization of the RCS at temperatures below the OPPS enable temperature specified in the PTLR could result in exceeding the ASME Appendix G (Ref. 3) brittle fracture P/T limits. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by restricting coolant input capability and ensuring adequate pressure relief capacity. In MODE 4, when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR, and above the safety injection (SI) pump disable temperature, limiting coolant input capability requires one (SI) pump incapable of injection into the RCS and isolating the emergency core cooling system (ECCS)

BASES

BACKGROUND (continued)

accumulators. In MODE 4, when any RCS cold leg temperature is $\leq$ the OPPS enable temperature specified in the PTLR, and above SI pump disable temperature, one PORV is the overpressure protection device that acts to terminate an increasing pressure event.

Limiting coolant input capability reduces the ability to provide core coolant addition. The LCO does not require the makeup control system deactivated or the SI actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the charging system can provide adequate flow. If conditions require the use of more than one SI pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

In MODE 4, above the SI pump disable temperature, pressure relief consists of two PORVs with reduced lift settings provided by OPPS. Two PORVs are required for redundancy. One PORV has adequate relieving capability to prevent overpressurization for the required coolant input capability.

As designed for the LTOP function, each PORV is signaled to open by OPPS if the RCS pressure approaches the lift setpoint provided when OPPS is enabled. The OPPS monitors both RCS temperature and RCS pressure and indicates when a condition not acceptable in the PTLR limits is approached. The wide range RCS temperature setpoints indicate conditions requiring enabling OPPS.

The PTLR presents the OPPS setpoints for LTOP.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 2) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperature exceeding the OPPS enable temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At about the OPPS enable

BASES

APPLICABLE SAFETY ANALYSES (continued)	temperature specified in the PTLR and below, overpressure prevention falls to two OPERABLE PORVs or to a depressurized RCS and a sufficiently sized RCS vent. Each of these means has a limited overpressure relief capability. LCO 3.4.13, "LTOP – RCSCLT ≤ SI Pump Disable Temperature," provides the requirements for overpressure prevention at the lower temperatures.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the PORV method.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 2 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients. The bounding mass input transient is inadvertent safety injection with injection from one SI pump and three charging pumps, and letdown isolated. The bounding heat input transient is reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following limitations are required during the Applicability of this Specification to ensure that mass and heat input transients in excess of analysis assumptions do not occur:

a. Rendering one SI pump incapable of injection;

b. Deactivating the ECCS accumulator discharge isolation valves in their closed positions; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Disallowing start of an RCP if secondary temperature is above primary temperature in any one loop. LCO 3.4.6, “RCS Loops - MODE 4,” provides this protection.

The Reference 2 analyses demonstrate that one PORV can maintain RCS pressure below limits when only one SI pump and all charging pumps are actuated. Thus, the LCO allows only one SI pump OPERABLE during the Applicability of this Specification.

Since one PORV cannot handle the pressure transient resulting from ECCS accumulator injection, when RCS temperature is low, the LCO also requires ECCS accumulator isolation when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated ECCS accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

Fracture mechanics analyses established the temperature of LTOP Applicability at the OPPS enable temperature specified in the PTLR.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 , when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR, and above the SI Pump disable temperature conform to 10 CFR 50.46 and 10 CFR 50, Appendix K, requirements by having a maximum of one SI pump OPERABLE and SI actuation enabled.

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The OPPS setpoints are derived by analyses that model the performance of the system, assuming the limiting LTOP transient of one SI pump and all charging pumps injecting into the RCS. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and

BASES

APPLICABLE SAFETY ANALYSES (continued)	valve stroke times. The OPPS setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met. The OPPS setpoints in the PTLR will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations. The LTOP function satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that LTOP be provided, by limiting coolant input capability and by OPERABLE pressure relief capability. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient. To limit the coolant input capability, the LCO requires that a maximum of one SI pump be capable of injecting into the RCS, and all ECCS accumulator discharge isolation valves be closed and de-energized (when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR). The LCO is modified by two Notes. Note 1 allows operation of both SI pumps for ≤ 1 hour for conducting SI system testing providing there is a steam or gas bubble in the pressurizer and at least one isolation valve between the SI pump and the RCS is shut. The purpose of this Note is to permit the conduct of the integrated SI test and other SI system tests and operations that may be performed in MODE 4. In this case, pressurizer level is maintained at less than 50% and a positive means of isolation is provided between the SI pumps and the RCS to prevent fluid injection to the RCS. This

BASES

LCO (continued)

isolation is accomplished by either a closed manual valve or motor operated valve with the power removed. This combination of conditions under strict administrative control assure that overpressurization cannot occur. Note 2 states that ECCS accumulator isolation is only required when the ECCS accumulator pressure is more than or at the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR (less allowance for instrument uncertainty). This Note permits the ECCS accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

To provide low temperature overpressure mitigation through pressure relief, the LCO requires an OPERABLE OPPS with two pressurizer PORVs. A PORV is OPERABLE for LTOP when its block valve is open, its low pressure lift setpoint has been selected (OPPS enabled), and the backup air supply is charged.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR and > the SI Pump disable temperature specified in the PTLR. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above the OPPS enable temperature specified in the PTLR.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above the OPPS enable temperature specified in the PTLR. LCO 3.4.13 provides the LTOP requirements in MODE 4 ≤ SI pump disable temperature and in MODES 5 and 6.

BASES

APPLICABILITY (continued)

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b when LTOP LCO requirements are not met. There is an increased risk associated with operating in MODE 4 at low temperatures with LTOP LCO requirements not met and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A-1

With two SI pumps capable of injecting into the RCS, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

B.1, C.1, and C.2

An unisolated ECCS accumulator requires isolation within 1 hour. This is only required when the ECCS accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

BASES

ACTIONS

B.1, C.1, and C.2 (continued)

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > the OPPS enable temperature specified in the PTLR, an accumulator pressure of 800 psig cannot exceed the LTOP analysis limits if the ECCS accumulators are fully injected. Depressurizing the ECCS accumulators below the LTOP limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

D.1

In MODE 4 when any RCS cold leg temperature is ≤ the OPPS enable temperature specified in the PTLR, with one required PORV inoperable, the PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the PORVs is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

BASES

ACTIONS (continued)

E.1

MODE 5 must be entered, the RCS must be depressurized and a vent must be established within 12 hours when:

a. Both PORVs are inoperable; or

b. A Required Action and associated Completion Time of Condition A, C, or D is not met; or

c. The OPPS is inoperable.

The vent must be sized ≥ 3 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. The vent opening is based on the cross sectional flow area of a PORV. A PORV maintained in the open position satisfies the vent requirement. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, one SI pump is verified incapable of injecting into the RCS and the ECCS accumulator discharge isolation valves are verified closed and de-energized.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2 (continued)

The SI pump is rendered incapable of injecting into the RCS by employing at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pullout and with a blocking device installed over the control switch that would prevent an unplanned pump start.

The ECCS accumulator motor operated isolation valves can be verified closed and de-energized by use of control board indication.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.12.3

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve can be remotely verified open in the main control room.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required to be removed, and the manual operator is not required to be locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72 hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

Performance of a COT is required every 31 days on OPPS to verify and, as necessary, adjust the PORV lift setpoints. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions. The COT will verify the setpoints are within the PTLR allowed maximum limits in the PTLR. PORV actuation during this testing could depressurize the RCS and is not required.

A Note has been added indicating that this SR is required to be performed 12 hours after decreasing RCS cold leg temperature to ≤ the OPPS enable temperature specified in the PTLR. The COT may not have been performed before entry into the LTOP MODES. The 12 hour initial time considers the unlikelihood of a low temperature overpressure event during this time.

SR 3.4.12.5

Performance of a CHANNEL CALIBRATION on OPPS is required every 24 months to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix G.

2. USAR, Section 4.4.

3. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G, with ASME Code Case N-514.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 Low Temperature Overpressure Protection (LTOP) Reactor Coolant System Cold Leg Temperature (RCSCLT) ≤ Safety Injection (SI) Pump Disable Temperature

BASES

BACKGROUND

The LTOP function limits RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The Over Pressure Protection System (OPPS) provides the actuation setpoints for the pressurizer power operated relief valves (PORVs) for the LTOP function (Ref. 2). The PTLR provides the maximum allowable OPPS actuation setpoints and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES. The LTOP MODES are the MODES as defined in the Applicability statement of LCO 3.4.12 and LCO 3.4.13.

The pressurizer safety valves and PORVs at their normal setpoints do not provide overpressure protection for certain low temperature operational transients. Inadvertent pressurization of the RCS at temperatures below the OPPS enable temperature specified in the PTLR could result in exceeding the ASME Appendix G (Ref. 3) brittle fracture P/T limits. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by restricting coolant input capability and ensuring adequate pressure relief capacity. In MODE 4, at or below the safety injection (SI) pump disable temperature, limiting coolant input capability requires both SI pumps incapable of injection into the RCS and isolating the emergency core cooling system (ECCS) accumulators. The pressure

BASES

BACKGROUND (continued)

relief capacity requires either two redundant PORVs or a depressurized RCS and an RCS vent of sufficient size. One PORV or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

Limiting coolant input capability reduces the ability to provide core coolant addition. The LCO does not require the makeup control system deactivated or the safety injection SI actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the charging system can provide adequate flow. If conditions require the use of an SI pump for makeup in the event of loss of inventory, the pump can be made available through manual actions.

The LTOP pressure relief consists of two PORVs with reduced lift settings provided by OPPS or a depressurized RCS and an RCS vent of sufficient size. Two PORVs are required for redundancy. One PORV has adequate relieving capability to prevent overpressurization for the required coolant input capability.

OPPS and PORV Requirements

As designed for the LTOP function, each PORV is signaled to open by OPPS if the RCS pressure approaches the lift setpoint provided when OPPS is enabled. The OPPS monitors both RCS temperature and RCS pressure and indicates when a condition not acceptable in the PTLR limits is approached. The wide range RCS temperature setpoints indicate conditions requiring enabling OPPS. The PTLR presents the OPPS setpoints for LTOP.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure

BASES

BACKGROUND

RCS Vent Requirements (continued)

in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 2) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperature exceeding the OPPS enable temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At about the OPPS enable temperature specified in the PTLR and below, overpressure prevention falls to two OPERABLE PORVs or to a depressurized RCS and a sufficiently sized RCS vent. Each of these means has a limited overpressure relief capability. LCO 3.4.12, "LTOP – RCSCLT > SI Pump Disable Temperature," provides the requirements for overpressure prevention at temperatures above the SIP disable temperature.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the PORV method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 2 analyses to determine the impact of the change on the LTOP acceptance limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients. The bounding mass input transient is inadvertent safety injection with injection from one SI pump and three charging pumps, and letdown isolated. The bounding heat input transient is reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following limitations are required during the Applicability of this specification to ensure that mass and heat input transients in excess of analysis assumptions do not occur:

a. Rendering both SI pumps incapable of injection;

b. Deactivating the ECCS accumulator discharge isolation valves in their closed positions; and

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.6, “RCS Loops - MODE 4,” provides this protection.

The Reference 2 analyses demonstrate that either one PORV or the depressurized RCS and RCS vent can maintain RCS pressure below limits when all charging pumps are actuated. Neither one PORV nor the RCS vent can handle the pressure transient resulting from inadvertent SI pump or ECCS accumulator injection when the RCS is below the SI Pump disable temperature. Thus, the LCO requires both SI pumps to be disabled below the temperature specified in the PTLR.

The LCO also requires ECCS accumulator isolation when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR. The isolated ECCS accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Fracture mechanics analyses established the temperature of LTOP Applicability at the OPPS enable temperature specified in the PTLR. The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The OPPS setpoints are derived by analyses that model the performance of the system, assuming the limiting LTOP transient of all charging pumps injecting into the RCS. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The OPPS setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met.

The OPPS setpoints in the PTLR will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” discuss these examinations.

With the RCS depressurized, analyses show a vent size equivalent to the cross sectional flow area of a PORV is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, both SI pumps disabled and all charging pumps OPERABLE when the RCS is below the SI Pump disable temperature, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

The RCS vent is passive and is not subject to active failure.

The LTOP function satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

This LCO requires that LTOP be provided, by limiting coolant input capability and by OPERABLE pressure relief capability. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires both SI pumps be incapable of injecting into the RCS, and all ECCS accumulator discharge isolation valves be closed and deenergized (when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR).

The LCO is modified by three Notes. Note 1 allows operation of both SI pumps for ≤ 1 hour for conducting SI system testing providing there is a steam or gas bubble in the pressurizer and at least one isolation valve between the SI pump and the RCS is shut. The purpose of this note is to permit the conduct of the integrated SI test and other SI system tests and operations that may be performed in MODES 4, 5 or 6. In this case, pressurizer level is maintained at less than 50% and a positive means of isolation is provided between the SI pumps and the RCS to prevent fluid injection to the RCS. This isolation is accomplished by either a closed manual valve or motor operated valve with the power removed. This combination of conditions under strict administrative control assure that overpressurization cannot occur.

Note 2 allows operation of an SI pump during reduced inventory conditions as required to maintain adequate core cooling and RCS inventory. The purpose of this note is to allow use of an SI pump in the event of a loss of other injection capability (e.g., loss of Residual Heat Removal System cooling while in reduced inventory conditions). The operation of an SI pump under such conditions would be controlled by an approved emergency operating procedure.

BASES

LCO (continued)	Note 3 states that ECCS accumulator isolation is only required when ECCS accumulator pressure is more than or at the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR (less allowance for instrument uncertainty). This Note permits the ECCS accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions. The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are: a. An OPERABLE OPPS with two PORVs; or A PORV is OPERABLE for LTOP when its block valve is open, its low pressure lift setpoint has been selected (OPPS enabled), and the backup air supply is charged. b. A depressurized RCS and an RCS vent. An RCS vent is OPERABLE when open with an area of ≥ 3.0 square inches. Because the RCS vent opening specification is based on the flow capacity of a PORV, a PORV maintained in the open position may be utilized to meet the RCS vent requirement. Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.
APPLICABILITY	This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ the SI Pump disable temperature specified in the PTLR, in MODE 5, and in MODE 6 when the reactor vessel head is on and the SG primary system manways and pressurizer manway are closed and secured. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above the OPPS enable temperature specified in the PTLR. When the reactor vessel head is off, overpressurization cannot occur.

BASES

APPLICABILITY (continued)	LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above the OPPS enable temperature specified in the PTLR. LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) – Reactor Coolant System Cold Leg Temperature (RCSCLT) ≤ Safety Injection Pump (SI) Pump Disable Temperature," provides the requirements for MODE 4 below the OPPS enable temperature and above the SI Pump disable temperature. Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.
ACTIONS	A Note prohibits the application of LCO 3.0.4.b when LTOP LCO requirements are not met. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP requirements not met and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance <u>A.1</u> With one or more SI pumps capable of injecting into the RCS, RCS overpressurization is possible. To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

BASES

ACTIONS (continued)

B.1, C.1, and C.2

An unisolated ECCS accumulator requires isolation within 1 hour. This is only required when the ECCS accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > the OPPS enable temperature specified in the PTLR, an ECCS accumulator pressure of 800 psig cannot exceed the LTOP analysis limits if the ECCS accumulators are fully injected. Depressurizing the ECCS accumulators below the LTOP limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

D.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature. Thus, with one PORV inoperable in MODE 4 when any RCS cold leg temperature is ≤ the SI Pump disable temperature specified in the PTLR, MODE 5 or in MODE 6 with the head on, the Completion Time to restore two valves to OPERABLE status is 24 hours. A Note clarifies that Condition D is only applicable when the OPPS and PORVs are being used to satisfy the pressure relief requirements of LCO 3.4.13.a.

BASES

ACTIONS

D.1 (continued)

The Completion Time represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one OPERABLE PORV to protect against overpressure events.

E.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required PORVs are inoperable; or

b. A Required Action and associated Completion Time of Condition A, C, or D is not met; or

c. The OPPS is inoperable.

The vent must be sized ≥ 3 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. The vent opening is based on the cross sectional flow area of a PORV. A PORV maintained in the open position satisfies the vent requirement. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 and SR 3.4.13.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, both SI pumps are verified incapable of injecting into the RCS and the ECCS accumulator discharge isolation valves are verified closed and deenergized.

The SI pumps are rendered incapable of injecting into the RCS by employing at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pullout with a blocking device installed over the control switch that would prevent an unplanned pump start.

The ECCS accumulator motor operated isolation valves can be verified closed and deenergized by use of control board indication.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.13.3

The RCS vent of ≥ 3 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked.

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position). A removed pressurizer safety valve or open manway also fits this category.

The passive vent path arrangement must only be open when required to be OPERABLE. This Surveillance is required if the vent is being used to satisfy the pressure relief requirements of LCO 3.4.13b.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.4

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve may be remotely verified open in the main control room. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required to be removed, and the manual operator is not required to be locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72 hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.13.5

Performance of a COT is required every 31 days on OPPS to verify and, as necessary, adjust the PORV lift setpoints. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The COT will verify the setpoints are within the PTLR allowed maximum limits in the PTLR. PORV actuation during this testing could depressurize the RCS and is not required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.5 (continued)

A Note has been added indicating that this SR is not required to be performed until 12 hours after decreasing RCS cold leg temperature to ≤ the OPPS enable temperature specified in the PTLR. The COT may not have been performed before entry into the LTOP MODES. The 12 hour initial time considers the unlikehood of a low temperature overpressure event during this time.

SR 3.4.13.6

Performance of a CHANNEL CALIBRATION on OPPS is required every 24 months to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

REFERENCES

1. 10 CFR 50, Appendix G.

2. USAR, Section 4.4.

3. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G, with ASME Code Case N-514.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. RCS component joints are made by welding, bolting, rolling, or pressure loading. Valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

AEC GDC Criterion 16 (Ref. 1), requires means for monitoring the reactor coolant pressure boundary to detect LEAKAGE. LCO 3.4.16, "RCS Leakage Detection Instrumentation," describes requirements for leakage detection instrumentation.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety analyses, which presume the occurrence of an RCS iodine spike concurrent with an accident, address operational LEAKAGE. The total operational LEAKAGE is used to determine the iodine appearance rate. In addition, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes the total primary to secondary LEAKAGE is 1 gallon per minute (i.e., 1 gpm at 70°F, 1.42 gpm at 578°F; hereafter described nominally as 1 gpm) from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident, and other accidents or transients that involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The USAR (Ref. 2) analysis for SGTR assumes the plant has been operating with a primary to secondary leak rate for a period of time sufficient to establish radionuclide equilibrium in the secondary loop at the applicable limits.

The safety analysis for the SLB accident assumes the total primary to secondary LEAKAGE is 1 gallon per minute from the faulted SG or is assumed

BASES

APPLICABLE SAFETY ANALYSES (continued)

to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. The safety analysis for other secondary side accidents assume a steady state leakage of 150 gpd to the intact Steam Generator(s).

The safety analysis assumes the leakage from the faulted SG will be limited to 1 gpm. The dose consequences resulting from the secondary side accidents are well within the limits defined in 10 CFR 50.67 or the staff approved licensing basis (i.e., a small fraction of these limits).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the reactor coolant pressure boundary (RCPB). LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

Seal welds are provided at the threaded joints of all reactor vessel head penetrations (spare penetrations, full-length Control Rod Drive Mechanisms, and thermocouple columns). Although these seals are part of the RCPB as defined in 10CFR50 Section 50.2, minor leakage past the seal weld is not a fault in the RCPB or a structural integrity concern. Pressure retaining components are differentiated from leakage barriers in the ASME Boiler and Pressure Vessel Code. In all cases, the joint strength is provided by the threads of the closure joint.

BASES

LCO (continued)

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified leakage must be evaluated to assure that continued operation is safe. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, “The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day.” The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.15, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE in excess of the LCO limits must be identified or reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1, B.2.1, and B.2.2

If unidentified LEAKAGE cannot be identified or cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals, gaskets, and pressurizer safety valves seats is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours. If the LEAKAGE source cannot be identified within 54 hours, then the reactor must be placed in MODE 5 within 84 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

BASES

ACTIONS

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

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

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

If RCS identified LEAKAGE, other than pressure boundary LEAKAGE or primary to secondary LEAKAGE, is not within limits, then the reactor must be placed in MODE 3 within 6 hours. In this condition, 14 hours are allowed to reduce the identified leakage to within limits. If the identified LEAKAGE is not within limits within this time, the reactor must be placed in MODE 5 within 44 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions in an orderly manner without challenging plant systems.

D.1 and D.2

If RCS pressure boundary LEAKAGE exists or if primary to secondary LEAKAGE (150 gpd limit) is not within limits, the reactor must be placed in MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions in an orderly manner without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions (stable temperature, power level, equilibrium xenon, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by monitoring containment atmosphere radioactivity. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.16, “RCS Leakage Detection Instrumentation.”

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

The 24 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 3.4.14.2

This SR verifies that primary to secondary LEAKAGE is less or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.19, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 4).

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 16, issued for comment July 10, 1967, as referenced in USAR, Section 1.2.

2. USAR, Section 14.5.

3. NEI 97-06, "Steam Generator Program Guidelines."

4. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

RCS PIVs separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.14, “RCS Operational LEAKAGE.” This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.14.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressurization of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

The basis for this LCO is the 1975 NRC “Reactor Safety Study” (Ref. 1) that identified potential intersystem LOCAs as a significant

BASES

BACKGROUND (continued)	contributor to the risk of core melt. A subsequent study (Ref. 2) evaluated various PIV configurations to determine the probability of intersystem LOCAs. PIVs are provided to isolate the RCS from low pressure systems susceptible to intersystem LOCAs. The PIVs are listed in the LCO section of these Bases. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.
APPLICABLE SAFETY ANALYSES	Reference 1 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the Residual Heat Removal (RHR) System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. The low pressure portion of the RHR System is designed for 600 psig. An overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent increased risk of core melt. Reference 2 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA. A plant specific review against the NRC criteria for intersystem LOCAs was performed to identify the most risk significant configurations (Ref. 3). Valves identified in this study are listed in the LCO discussion in these Bases. RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

RCS PIV OPERABILITY protects the low pressure systems attached to the RCS from potential failure due to overpressurization. This protection (that is, RCS PIV OPERABILITY) is provided by the leak tight PIVs.

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. This LCO only applies to the following PIVs which were determined to be in the most risk significant configurations (Ref. 3):

a. Residual Heat Removal (RHR) System, RHR to loop B accumulator injection line:

Unit 1	SI-6-2
Unit 2	2SI-6-2

b. Safety Injection (SI) System, low pressure SI to upper plenum:

Unit 1	SI-9-3, SI-9-4, SI-9-5, SI-9-6
Unit 2	2SI-9-3, 2SI-9-4, 2SI-9-5, 2SI-9-6

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value.

Reference 4 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal

BASES

LCO (continued)

pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path when an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The flow path must be isolated by two valves. Required Action A.1 is modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected

BASES

ACTIONS

A.1 and A.2 (continued)

system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the leaking PIV be restored within limits.

The 72 hour Completion Time after exceeding the limit allows for the restoration of the leaking PIV to OPERABLE status. This timeframe considers the time required to complete this Action and the low probability of a second valve failing during this period.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 is required to verify that leakage is below the specified limit and to identify each leaking valve.

The leakage limit of 0.5 gpm per inch of nominal valve diameter up

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1 (continued)

to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition of at least 150 psid.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed at the following times:

a. Every 24 months, a typical refueling cycle;

b. Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months.

The 24 month Frequency is consistent with 10 CFR 50.55a(g) as contained in the Inservice Testing Program, is within the frequency allowed by Reference 4, and is based on the need to perform such surveillances under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1 (continued)

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures. A differential pressure of at least 150 psid is sufficient to ensure the valves are seated.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

REFERENCES

1. WASH-1400 (NUREG-75/014), Appendix V, October 1975.

2. NUREG-0677, May 1980.

3. Letter from Robert A. Clark, NRC, to L. O. Mayer, NSP, Subject: "Order for Modification of License Concerning Primary Coolant System Pressure Isolation Valves," dated April 20, 1981.

4. American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

AEC GDC 16 (Ref. 1) requires that means be provided for monitoring reactor coolant pressure boundary (RCPB) to detect RCS LEAKAGE. Reference 2 describes methods used for RCS leakage detection.

Leakage detection systems must have the capability to detect significant RCPB degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump A pump run time instrumentation may be used to detect increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-9} μCi/cc radioactivity for particulate monitoring and of 10^{-6} μCi/cc radioactivity for gaseous monitoring are practical for these leakage detection systems. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

The containment atmosphere radiation monitoring channel, R-11, normally provides the required monitoring.

BASES

BACKGROUND (continued)	An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Humidity measurements can be used as a less sensitive indicator of potential RCS LEAKAGE (Ref. 2). Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed changes in containment sump A pump run time. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO. Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.
APPLICABLE SAFETY ANALYSES	The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the USAR (Refs. 2 and 3). Multiple instrument locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into containment is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public.

Containment radionuclide monitoring used for RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii). Containment sump A monitoring used for RCS leakage detection instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available to provide indication of RCS leakage. Thus, the containment sump A monitor (pump run time instrumentation), in combination with a containment radionuclide monitor, provides an acceptable minimum.

BASES (continued)

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the required containment sump monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment radionuclide monitor will provide indications of changes in leakage. Together with the radionuclide monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.14.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. A Note is added allowing that SR 3.4.14.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, equilibrium xenon, pressurizer and makeup tank levels, makeup and letdown, and reactor coolant pump seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

BASES

ACTIONS

A.1 and A.2 (continued)

Restoration of the required sump monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

B.1.1, B.1.2, and B.2

When the required containment radionuclide monitoring instrumentation channel is inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.14.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment radionuclide monitor.

The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1 and C.2

If a Required Action of Condition A or B cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating

BASES

ACTIONS

C.1 and C.2 (continued)

experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

With all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires the performance of a CHANNEL CHECK of the required containment radionuclide monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.16.2

SR 3.4.16.2 requires the performance of a COT on the required containment radionuclide monitor. The test ensures that the monitor can perform its function in the desired manner. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The test verifies the alarm

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.2 (continued)

setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.16.3 and SR 3.4.16.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is a typical refueling cycle and considers channel reliability.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 16, issued for comment July 10, 1967, as referenced in USAR Section 1.2.
2. USAR, Section 6.5.
3. USAR, Section 7.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 RCS Specific Activity

BASES

BACKGROUND

The maximum dose that an individual at the exclusion area boundary can receive for 2 hours following an accident, or at the low population zone outer boundary for the radiological release duration, is specified in 10 CFR 50.67 (Ref. 1). The limits on specific activity ensure that the offsite and control room doses are appropriately limited during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the dose consequences in the event of a steam generator tube rupture (SGTR) accident. The DOSE EQUIVALENT I-131 limit has been established to ensure that the control room dose acceptance criteria are met following a main steam line break (MSLB).

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and control room doses meet the appropriate acceptance criteria in the Standard Review Plan (Ref. 2). The LCO limit for DOSE EQUIVALENT I-131 was derived from the control room dose consequence analysis following a MSLB.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite and control room doses meet the appropriate Standard Review Plan (SRP) acceptance criteria following a MSLB or SGTR accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.14, “Secondary Specific Activity.”

The analyses for the MSLB and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to acceptance limits.

The safety analyses consider two cases of reactor coolant iodine specific activity. One case assumes specific activity at 0.5 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of release of iodine from the fuel rods containing cladding defects to the reactor coolant immediately after a MSLB (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity at 30.0 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor of an RCS transient prior to the accident. In both cases, the noble gas specific activity is assumed to be 580 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis also assumes a loss of offsite power at the same time as the reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured steam generator (SG) discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the Residual Heat Removal (RHR) system is placed in service.

The SLB radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside containment. Reactor

BASES

APPLICABLE SAFETY ANALYSES (continued)

trip occurs after the generation of an SI signal on low steam line pressure. The affected SG blows down completely and steam is vented directly to the atmosphere. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the RHR system is placed in service.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed 30.0 µCi/gm for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to 0.5 µCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 580 µCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that offsite and control room doses will meet appropriate SRP acceptance criteria (Ref. 2).

The SGTR and MSLB accident analysis (Ref. 3) show that the calculated doses are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the SRP acceptance criteria (Ref. 2).

APPLICABILITY

In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of a SGTR or MSLB to within the SRP acceptance criteria (Ref. 2).

BASES

APPLICABILITY (continued)

In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, monitoring of RCS specific activity is not required.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the specific activity is ≤ 30 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is required, if the limit violation resulted from normal iodine spiking.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1

With the DOSE EQUIVALENT XE-133 greater than the LCO limit, DOSE EQUIVALENT XE-133 must be restored to within limit within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period.

BASES

ACTIONS

B.1 (continued)

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Action B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

C.1 and C.2

If a Required Action and the associated Completion Time of Condition A or B is not met, or if the DOSE EQUIVALENT I-131 > 30 μCi/gm, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

SR 3.4.17.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in the noble gas specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The 7 day Frequency considers the unlikelihood of a gross fuel failure during the time.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.17.1

Due to the inherent difficulty in detecting Kr-85 in a reactor coolant sample due to masking from radioisotopes with similar decay energies, such as F-18 and I-134, it is acceptable to include the minimum detectable activity for Kr-85 in the SR 3.4.17.1 calculation. If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 is not detected, it should be assumed to be present at the minimum detectable activity.

SR 3.4.17.2

The 14 day Frequency is adequate to trend changes in the iodine activity level, considering gross activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

REFERENCES

1. 10 CFR 50.67.
2. SRP Section 15.0.1, “Radiological Consequence Analyses Using Alternative Source Terms”.
3. USAR, Section 14.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 RCS Loops - Test Exceptions

BASES

BACKGROUND

The primary purpose of this test exception is to provide an exception to LCO 3.4.4, "RCS Loops - MODES 1 and 2," to permit reactor criticality under no flow conditions during certain PHYSICS TESTS (natural circulation demonstration, station blackout, and loss of offsite power) to be performed while at low THERMAL POWER levels. Section XI of 10 CFR 50, Appendix B, requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the power plant as specified in AEC GDC Criterion 1 (Ref. 1).

The key objectives of a test program are to provide assurance that the facility has been adequately designed to validate the analytical models used in the design and analysis, to verify the assumptions used to predict plant response, to provide assurance that installation of equipment at the unit has been accomplished in accordance with the design, and to verify that the operating and emergency procedures are adequate. Testing is performed prior to initial criticality, during startup, and following low power operations.

APPLICABLE SAFETY ANALYSES

Operating the plant without forced convection flow is not bounded by any safety analyses. However, operating experience has demonstrated this exception to be safe under the present applicability.

As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exception LCOs provide flexibility to perform certain

BASES

APPLICABLE SAFETY ANALYSES (continued)	operations by appropriately modifying requirements of other LCOs. A discussion of the criteria for the other LCOs is provided in their respective Bases.
LCO	This LCO provides an exemption to the requirements of LCO 3.4.4. The LCO is provided to allow for the performance of PHYSICS TESTS in MODE 2 (after a refueling), where the core cooling requirements are significantly different than after the core has been operating. Without the LCO, plant operations would be held bound to the normal operating LCOs for reactor coolant loops and circulation (MODES 1 and 2), and the appropriate tests could not be performed. In MODE 2, where core power level is considerably lower and the associated PHYSICS TESTS must be performed, operation is allowed under no flow conditions provided THERMAL POWER is ≤ P-7 and the reactor trip setpoints of the OPERABLE power level channels are set ≤ the allowable value of Table 3.3.1-1, Function 2.b. This ensures, if some problem caused the plant to enter MODE 1 and start increasing plant power, the Reactor Trip System (RTS) would automatically shut it down before power became too high, and thereby prevent violation of fuel design limits. The exemption is allowed even though there are no bounding safety analyses. However, these tests are performed under close supervision during the test program and provide valuable information on the plant's capability to cool down without offsite power available to the reactor coolant pumps.
APPLICABILITY	This LCO is applicable when performing low power PHYSICS TESTS without any forced convection flow. This testing is performed to establish that heat input from nuclear heat does not

BASES

APPLICABILITY (continued)

exceed the natural circulation heat removal capabilities. Therefore, no safety or fuel design limits will be violated as a result of the associated tests.

ACTIONS

A.1

When THERMAL POWER is ≥ the P-7 interlock setpoint, the only acceptable action is to ensure the reactor trip breakers (RTBs) are opened immediately in accordance with Required Action A.1 to prevent operation of the fuel beyond its design limits. Opening the RTBs will shut down the reactor and prevent operation of the fuel outside of its design limits.

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

Verification that the power level is < the P-7 interlock setpoint will ensure that the fuel design criteria are not violated during the performance of the PHYSICS TESTS. The Frequency of once per hour is adequate to ensure that the power level does not exceed the limit. Plant operations are conducted slowly during the performance of PHYSICS TESTS and monitoring the power level once per hour is sufficient to ensure that the power level does not exceed the limit.

SR 3.4.18.2

The power range and intermediate range neutron channels and the P-7 interlock setpoint must be verified to be OPERABLE and adjusted to the proper value. A COT is performed prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.18.2 (continued)

This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction," Criterion 1, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.19 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, “RCS Loops - MODES 1 and 2,” LCO 3.4.5, “RCS Loops - MODE 3,” LCO 3.4.6, “RCS Loops - MODE 4,” and LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled.”

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.8, “Steam Generator (SG) Program,” requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.8, tube integrity is maintained when the SG performance criteria are met.

BASES

BACKGROUND (continued)

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.8. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate at the operational LEAKAGE rate limits in LCO 3.4.14, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via the associated steam generator PORV.

The analyses for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE of 1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to or greater than the LCO 3.4.17, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 50.67 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, an SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

BASES

LCO (continued)

An SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.8, “Steam Generator Program,” and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, “The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation.”

Tube collapse is defined as, “For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero.” The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term “significant” is defined as “An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established.” For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be

LCO (continued)

evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than an SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed those discussed in the APPLICABLE SAFETY ANALYSES section above. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.14, “RCS Operational LEAKAGE,” and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to an SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

BASES (continued)

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4. RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

<u>A.1 and A.2</u>

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.19.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if an SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered

BASES

ACTIONS

A.1 and A.2 (continued)

and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with an SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.19.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.19.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.8 contains prescriptive requirements concerning inspection

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.19.1 (continued)

intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 5.5.8 until subsequent inspections support extending the inspection interval.

SR 3.4.19.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.5.8 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following an SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

BASES (continued)

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."

2. 10 CFR 50 Appendix A, GDC 19.

3. 10 CFR 50.67.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.

6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a large break loss of coolant accident (LOCA), to provide inventory to help accomplish the refill and reflood phases that follow thereafter, and to provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The reactor coolant inventory is vacating the core during this phase through steam flashing and ejection out through the break. The blowdown phase of the transient ends when the collapsed liquid level in the lower plenum reaches a minimum and begins to increase.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is available to help fill voids in the lower plenum and reactor vessel downcomer, and to help the ongoing reflood of the core with the addition of water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

BASES

BACKGROUND (continued)

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series. The motor operated isolation valves are MV 32071 and MV 32072 (Unit 2 - MV 32174 and MV 32175) (Westinghouse valve numbers 8800A and 8800B respectively for both units).

The accumulator size, water volume, and nitrogen cover pressure are selected so that one of the two accumulators is sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that one accumulator is adequate for this function is consistent with the large break LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 1). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a large break LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The largest break area considered for a large break LOCA is a double ended guillotine break in the RCS cold leg. During this event, the accumulator discharges to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for safety injection (SI) signal generation, the diesels starting (for loss of offsite power assumption) and the pumps being loaded and delivering full flow. Prior to this delay elapsing, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and safety injection pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the safety injection pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 will be met following a LOCA:

a. The calculated peak fuel element cladding temperature is below the requirement of 2200°F;

b. The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The localized cladding oxidation limits of 17% are not exceeded during or after quenching;

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. The amount of hydrogen generated by fuel element cladding that reacts chemically with water or steam does not exceed an amount corresponding to interaction of 1% of the total amount of Zircaloy in the reactor; and

d. The core remains amenable to cooling during and after the break.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

The large break LOCA analysis considers a range of accumulator water volumes based on minimum and maximum volumes of 1250 cubic feet (25% indicated level) and 1290 cubic feet (91% indicated level).

The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. For large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. For small breaks, a nominal accumulator water volume is assumed due to lack of a consistent conservative direction. Both large and small break analyses use a nominal accumulator line water volume from the accumulator to the check valve.

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment including both long term sump conditions and short term reflood conditions. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent

BASES

APPLICABLE SAFETY ANALYSES (continued)

reduction in the available containment sump concentration for post LOCA shutdown, a reduction in available core boron concentrations during reflood and an increase in the maximum sump pH. For conservatism, the accumulators are assumed at a conservatively high boron concentration in the boron build up analyses.

The small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The large break analyses utilize the nominal nitrogen cover pressure as per approved methods (Ref. 1). The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 1 and 2).

The accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Two accumulators are required to ensure that 100% of the contents of one accumulator will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than one accumulator is injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 could be violated.

For an accumulator to be considered OPERABLE, the motor-operated isolation valve must be fully open, power removed above 2000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

BASES (continued)

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 limit of 2200°F.

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood since the accumulator water volume is very small when compared to RCS and RWST inventory. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current

BASES

ACTIONS A.1 (continued)

analysis techniques demonstrate that the accumulators are not expected to discharge following a large main steam line break. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of one accumulator cannot be assumed to reach the core during a LOCA.

Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status were justified in Reference 3.

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the

BASES

ACTIONS

C.1 and C.1 (continued)

plant must be brought to MODE 3 within 6 hours and RCS pressure reduced to ≤ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If both accumulators are inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator motor operated valve should be verified to be fully open every 12 hours. Use of control board indication (position monitor lights and alarms) for valve position is an acceptable verification. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed or not fully open valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator. This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage.

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator isolation valve operator when the RCS pressure is ≥ 2000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only one accumulator would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

BASES (continued)

REFERENCES

1. USAR, Section 14.
2. USAR, Section 6.2.
3. WCAP-15049-A, Revision 1, “Risk-Informed Evaluation of an Extension to Accumulator Completion Times,” April 1999.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS-Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Loss of secondary coolant accident, including uncontrolled steam release; and

c. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are two phases of ECCS operation: injection and recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs and reactor vessel upper plenum. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sump has enough water to supply the required net positive suction head to the RHR pumps, suction is switched to containment Sump B for recirculation. When post accident RCS pressure drops below the RHR pump shutoff head, the RHR flow is directed into the reactor vessel upper plenum to reduce the boiling in the top of the core and any resulting boron precipitation.

BASES

BACKGROUND (continued)

The ECCS consists of two separate subsystems: safety injection (SI) and residual heat removal (RHR). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the RHR pumps, RHR heat exchangers, and the SI pumps. Both subsystems consist of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core if necessary due to individual component inoperability.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. Separate piping supplies each subsystem. The discharge from each SI pump divides and feeds an injection line to each of the RCS cold legs. Throttle valves are set to balance the flow to the RCS. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs. The discharge from each RHR pump divides and feeds an injection line to the reactor vessel upper plenum.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the steam generators provide core cooling until the RCS pressure decreases below the SI pump shutoff head.

BASES

BACKGROUND (continued)

During the recirculation phase of LOCA recovery, RHR pump suction is manually transferred to the containment sump. Initially, recirculation is through the same paths as the injection phase. The RHR pumps provide flow to the reactor vessel upper plenum. If the RCS pressure limits RHR flow, then the RHR pumps supply the SI pumps which provide flow to the cold legs.

The SI subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCOs 3.4.12, "Low Temperature Overpressure Protection (LTOP) > Safety Injection (SI) Pump Disable Temperature," and 3.4.13, "Low Temperature Overpressure Protection (LTOP) ≤ Safety Injection (SI) Pump Disable Temperature," for the basis of these requirements.

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguards loads is accomplished in a programmed time sequence. If offsite power is available, the safeguards loads start immediately in the programmed sequence. If offsite power is not available, the safeguards buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguards loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the length of time before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet AEC GDC 44 (Ref. 1).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptancecriteria for the ECCS, established by 10 CFR 50.46, will be met following a LOCA:

a. The calculated peak fuel element cladding temperature is below the requirement of 2200°F;

b. The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The localized cladding oxidation limits of 17% are not exceeded during or after quenching;

c. The amount of hydrogen generated by fuel element cladding that reacts chemically with water or steam does not exceed an amount corresponding to interaction of 1% of the total amount of Zircaloy in the reactor;

d. The core remains amenable to cooling during and after the break; and

e. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long-lived radioactivity remaining in the core.

The LCO also limits the potential for a post trip return to power following an MSLB event.

Both ECCS subsystems are taken credit for in a large break LOCA event at full power (Refs. 2 and 3). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The SI pumps are credited in small break LOCA, SGTR and MSLB events. The small break LOCA event establishes the flow and discharge head at the design point for the pumps. The SI pump head and flow characteristics also meet SGTR and MSLB requirements. The

BASES

APPLICABLE SAFETY ANALYSES (continued)

OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of a single ECCS train; and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected by the SI pumps into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core. The RHR pumps inject directly into the reactor vessel by upper plenum injection when the RCS pressure is less than the RHR pump shutoff head. The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 2 and 3). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For smaller LOCAs, the SI pumps deliver sufficient fluid to maintain RCS inventory. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents

BASES

LCO (continued)

In MODES 1, 2, and 3, an ECCS train consists of an SI subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and RHR capable of being transferred to take suction from containment Sump B.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the two cold leg injection nozzles and the reactor vessel upper plenum. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS cold legs or directly into the reactor vessel upper plenum.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

Manual valves that could, if improperly positioned, reduce injection flow below that assumed for accident analyses, are blocked and tagged or locked in the proper position for injection. Changes in valve position must be under direct administrative control.

A block is a device that can be unclipped or unsnapped to allow a status change of the component to which it is applied. A lock is a device that must be unlocked, destroyed or mechanically removed (such as a cap or blank) to allow a status change of the component to which it is applied.

As indicated in the LCO Note, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.15.1. The flow path is readily restorable from the control room.

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The SI pump performance requirements are based on a small break LOCA and meet required parameters for mitigation of a secondary side loss of fluid accident. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above.

In MODES 4, 5, and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. MODE 4 core cooling requirements are addressed by LCO 3.5.3, "ECCS-Shutdown," and LCO 3.4.6, "RCS Loops-MODE 4." Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

ACTIONS

A.1

With one or more trains inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 4) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or required supporting systems are not available.

BASES

ACTIONS

A.1 (continued)

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 4) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 5 describes situations in which one component, such as an RHR crossover valve, can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to

BASES

ACTIONS

B.1 and B.2 (continued)

a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

Condition A is applicable with one or more trains inoperable. The allowed Completion Time is based on the assumption that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. With less than 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the facility is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Use of control board indication for valve position is an acceptable verification. Misalignment of these valves could render one or both ECCS trains inoperable. These valves are secured in position by physically locking the motor control center supply breakers in the off position with the valve position monitor lights OPERABLE to assure that they cannot change position as a result of an active failure or be inadvertently misaligned. Verification of the valve breakers is performed by SR 3.5.2.3.

A 12 hour Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned valve is unlikely.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing (A seal is a device that must be destroyed to allow a status change of the component to which it is applied). A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

Verification every 31 days that the motor control center supply breakers are physically locked in the off position for each valve specified in SR 3.5.2.1 ensures that an active failure could not result in an undetected misposition of a valve. Since power is removed under administrative control and valve position is verified every 12 hours, the 31 day Frequency will provide adequate assurance that power is removed.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at a single point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is within the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5 and SR 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This test is met when control board indications and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, the appropriate pump breakers have opened and closed, and all automatic valves have been placed in the proper position required to establish a safety injection flow path to the reactor coolant system.

This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.5 and SR 3.5.2.6 (continued)

Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of Engineered Safety Feature (ESF) Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.7

Surveillance Requirements on ECCS throttle valves provide assurance that proper ECCS flows are maintained in the event of a LOCA. Proper flow resistance and pressure drop in the piping system to each injection point in the SI System is necessary to: 1) prevent total pump flow from exceeding runout conditions when the system is in its minimum resistance configuration; 2) provide the proper flow split between injection points in accordance with the assumptions used in the ECCS LOCA analyses; and 3) provide an acceptable level of total ECCS flow to all injection points equal to or above that assumed in the ECCS LOCA analyses. The 24 month Frequency is based on the same reasons as those stated in SR 3.5.2.5 and SR 3.5.2.6.

SR 3.5.2.8

Periodic inspections of the containment sump suction inlet to the RHR System ensure that it is unrestricted and stays in proper operating condition. The 24 month Frequency allows this Surveillance to be performed under the conditions that apply during a plant outage. This Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 44, issued for comment July 10, 1967, as referenced in USAR Section 1.2.

2. USAR, Section 6.2.

3. USAR, Section 14.

4. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

5. IE Information Notice No. 87-01.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS – Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS-Operating," is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of two separate subsystems: safety injection (SI) and residual heat removal (RHR).

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) or containment Sump B can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

In the event of a loss of coolant accident (LOCA) while in the Applicability of Technical Specification (TS) 3.5.3, fluid in the RHR suction piping could flash to steam, resulting in the RHR system not remaining capable of responding to the LOCA. Also, if a LOCA occurs in MODE 4 that is of sufficient size to depressurize and drain the RCS, any operating RHR pump could lose its suction source at some point. As a result, any operating RHR pump is assumed to fail if it is not shut down prior to steam and/or air voiding. See References 1 and 2.

These issues are similar in that they both relate to the RHR system's ability to mitigate a LOCA while in MODE 4, and similar corrective actions are required to address both concerns. However, the immediate precursor of each failure is distinctly different. The first concern is a result of trapped fluid in the RHR system remaining at a temperature that is sufficiently high such that flashing will occur when the system is depressurized. The second concern is due to the fact that during a LOCA of sufficient size to depressurize and drain the RCS any operating RHR pump would lose its suction source. Due to these issues, one RHR train must be aligned for ECCS

BASES

BACKGROUND (continued)	mode of operation to satisfy LCO 3.5.3 when in MODE 4.
APPLICABLE SAFETY ANALYSES	Due to the lower heat generation rate associated with operation in MODE 4 it has been judged that the full power licensing analyses described in the Applicable Safety Analyses section of Bases 3.5.2 would bound the consequences of a Design Basis Accident (DBA) in MODE 4. It is also recognized that due to the lower pressure and temperatures in the RCS, the probability of occurrence of a DBA is reduced. Therefore, the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic SI actuations are not available. In this MODE, the heat generation rate is lower and sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA. Therefore, only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered for this LCO due to the time available for operators to respond to an accident. The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

In MODE 4, an ECCS train consists of an SI subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the SI subsystem capable (through manual actions) of injecting into each of the cold leg injection nozzles and reactor vessel upper plenum nozzles. In the long term, a flow path is required to provide recirculation flow via the RHR subsystem from the containment sump into each of the reactor vessel upper plenum nozzles.

This LCO is modified by one Note which allows an SI train to be considered OPERABLE when the pump is capable of being manually started for ECCS injection from the control room.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

APPLICABILITY (continued)

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, “RCS Loops-MODE 5, Loops Filled,” and LCO 3.4.8, “RCS Loops-MODE 5, Loops Not Filled.” MODE 6 core cooling requirements are addressed by LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation-High Water Level,” and LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level.”

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS safety injection (SI) subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS SI subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed

BASES

ACTIONS

A.1 (continued)

from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

B.1

With no ECCS SI subsystem OPERABLE (neither train), due to the inoperability of the SI pump or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one SI subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

C.1

When the Required Actions of Conditions B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

BASES (continued)

SURVEILLANCE REQUIREMENTS	<u>SR 3.5.3.1</u> The applicable Surveillance descriptions from Bases 3.5.2 apply.
REFERENCES	The applicable references from Bases 3.5.2 apply. 1. NRC Information Notice 2010-11. 2. Westinghouse NSAL-09-8.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling pool during refueling, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies both trains of the ECCS and the Containment Spray System during the injection phase of a loss of coolant accident (LOCA). A motor operated isolation valve is provided in each header to isolate the RWST from the ECCS once the system has been transferred to the recirculation mode. The recirculation mode is entered when RHR pump suction is transferred to the containment sump following receipt of the RWST-Low Low Level alarm. Use of a single RWST to supply both trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with initiation of Design Basis Events.

The RWST is located in the Auxiliary Building which maintains the tank temperature above freezing and therefore maintains the boron soluble (Ref. 1).

During normal operation in MODES 1, 2, and 3, the safety injection (SI), residual heat removal (RHR), and Containment Spray (CS) pumps are aligned to take suction from the RWST.

The ECCS and CS pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions. The recirculation lines for the RHR pumps are directed from the discharge of the pumps to the pump suction. The recirculation lines for the SI and CS pumps are directed back to the RWST.

BASES

BACKGROUND (continued)	When the suction for the ECCS pumps is transferred to the containment sump, the RWST and SI pump recirculation flow paths must be isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the Auxiliary Building atmosphere and the eventual loss of suction head for the ECCS pumps. This LCO ensures that: a. The RWST contains sufficient borated water to support the ECCS during the injection phase; b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS pumps at the time of transfer to the recirculation mode of cooling; and c. The reactor remains subcritical following a LOCA. Insufficient water in the RWST could result in inadequate net positive suction head (NPSH) for the RHR pumps when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SHUTDOWN MARGIN (SDM) or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.
APPLICABLE SAFETY ANALYSES	During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS Operating"; B 3.5.3, "ECCS-Shutdown"; and B 3.6.5, "Containment Spray and Cooling Systems." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RWST must also meet volume and boron concentration requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is determined by the volume of water required in the containment sump to provide the necessary NPSH for the RHR pumps at the time of switchover to recirculation. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The maximum boron concentration is an explicit assumption in the evaluation of chemical effects resulting from the operation of the CS System. Temperatures above freezing in the RWST in combination with the maximum boron concentration ensure that the boron will remain soluble while in the RWST.

For a large break LOCA analysis, the post LOCA sump boron concentration necessary to assure subcriticality was computed using the lower boron concentration limit of 2600 ppm and a volume of water less than the minimum borated water volume of 265,000 gallons (90% indicated level). The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

The upper limit on boron concentration of 3500 ppm is used in calculations which verify boron precipitation does not occur in the core following a LOCA. The upper limit on boron concentration is also used in containment sump chemistry calculations to assure that post-LOCA pH is within acceptable limits.

The RWST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and

BASES

LCO (continued)

to ensure adequate level in the containment sump to support ECCS pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume and boron concentration limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

ACTIONS

A.1

With RWST boron concentration not within limits, it must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST boron concentration to within limits was developed considering the time required to change the boron concentration and the fact that the contents of the tank are still available for injection.

B.1

With the RWST water volume not within limits, it must be restored to OPERABLE status within 1 hour.

BASES

ACTIONS

B.1 (continued)

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS pump operation on recirculation. Since the RWST volume is normally stable and the RWST is located in the Auxiliary Building which provides leak detection capability, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.5.4.2 The boron concentration of the RWST should be verified every 7 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.
REFERENCES	1. USAR, Section 6 and Section 14.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment is a free standing steel pressure vessel surrounded by a reinforced concrete shield building. The containment vessel, including all its penetrations, is a low leakage steel shell designed to contain radioactive material that may be released from the reactor core following a design basis Loss of Coolant Accident (LOCA). Additionally, the containment and shield building provide shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment vessel is a vertical cylindrical steel pressure vessel with a hemispherical dome and ellipsoidal bottom, completely enclosed by a reinforced concrete shield building. A 5 ft wide annular space exists between the walls of the steel containment vessel and the concrete shield building and 7 ft clearance exists between the roofs of the containment vessel and shield building to permit inservice inspection and collection of containment outleakage.

Containment piping penetration assemblies provide for the passage of process, service, sampling and instrumentation pipelines into the containment vessel while maintaining containment OPERABILITY. The shield building provides shielding and allows controlled release of the annulus atmosphere under accident conditions, as well as environmental missile protection for the containment vessel and the Nuclear Steam Supply System.

The inner steel containment and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50 Appendix J, Option B (Ref. 1), as modified by approved exemptions.

BASES

BACKGROUND (continued)

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

 1. capable of being closed by an OPERABLE automatic containment isolation system, or

 2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, “Containment Isolation Valves”;

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, “Containment Air Locks”; and

c. All equipment hatches are closed and sealed.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting Design Basis Accident (DBA) without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a LOCA and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The reactor containment vessel, including the penetrations, is designed for low leakage to minimize the consequences (dose) to the general public during a DBA. The maximum allowable containment leakage rate is an input to the dose analyses. In the Updated Safety Analysis Report (USAR), the maximum allowable containment leakage used in the large break

BASES

APPLICABLE SAFETY ANALYSES (continued)

LOCA dose analysis was 2.5 weight percent per day. In the SER, the AEC concluded that a maximum containment leakage of 0.5 weight percent per day was acceptable. This formed the basis for the original plant Technical Specification leakage limit of 0.5 weight percent per day. Subsequently, it was concluded that the Shield Building leakage was higher than anticipated which increased the calculated dose. With the higher Shield Building leakage, in order to reduce the calculated dose, the maximum allowable containment leakage was reduced to 0.25 weight percent per day. Subsequently, as part of the Alternative Source Term Dose Analysis for the loss of coolant accident, the maximum allowable containment leakage was further reduced to 0.15 weight percent per day (Ref. 2). This leakage rate, used in the evaluation of offsite doses resulting from accidents, is defined for Prairie Island in the Containment Leakage Rate Testing Program as L_a: the maximum allowable containment leakage rate at the containment design maximum internal pressure (P_a). The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.15% per day in the safety analysis at P_a = 46.0 psig (Ref. 2).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time, the applicable leakage rate limits must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2), purge valves with resilient seals, and secondary bypass

BASES

LCO (continued)

leakage (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a or exceeding the total maximum allowable secondary containment bypass leakage rates.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABLE during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable,

BASES

ACTIONS

B.1 and B.2 (continued)

based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock, and secondary containment (shield building and auxiliary building special ventilation zone) bypass leakage path limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be ≤ 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria are based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.2

Verifying that the maximum temperature differential between average containment and annulus air temperatures is less than or equal to 44 ^{o}F ensures that containment operation remains within the limits assumed for the containment analyses. Plant operating experience demonstrates that this limit can only be approached when the plant is in MODES 5 and 6. Requiring this temperature differential to be verified prior to entering MODE 4 from MODE 5 provides assurance this parameter is within acceptable limits prior to establishing conditions requiring containment integrity.

SR 3.6.1.3

Verifying that the minimum containment shell temperature is met ensures that adequate margin above NDTT exists. Plant operating experience demonstrates that this limit can only be approached when the plant is in MODES 5 and 6. Requiring containment shell temperature to be verified prior to entering MODE 4 from MODE 5 provides assurance that the shell temperature is above NDTT prior to establishing conditions requiring containment integrity.

REFERENCES

1. 10 CFR 50, Appendix J.

2. USAR, Section 14.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 10 ft in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a design basis accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication alerts the operator whenever both air lock doors are open which indicates the interlock mechanism is defeated.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 1). The Loss of Coolant Accident (LOCA) dose analysis bounds the rod ejection accident releases. In the LOCA analysis, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The assumed containment leakage rate is 0.15% of containment air weight per day (Ref. 1). This leakage rate is defined at Prairie Island in the Containment Leakage Rate Testing Program as L_a, the maximum allowable containment leakage rate at the containment internal design pressure P_a = 46.0 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the 10CFR50, Appendix J, Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events.

BASES

LCO (continued)	Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment. Normal entry into or exit from containment does not render the air lock inoperable.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."
ACTIONS	The ACTIONS are modified by three Notes. The first Note allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. For repairs to the inner door, it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from inside the air lock between the two doors then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

ACTIONS (continued)

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, “Containment.”

<u>A.1, A.2, and A.3</u>

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour and may consist of verifying the control board alarm status for the air lock doors. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A, only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

BASES

ACTIONS (continued)

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B (e.g., both doors of an air lock are inoperable), Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation per LCO 3.6.1 is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal

ACTIONS

C.1, C.2, and C.3 (continued)

test or if the overall air lock leakage is not within the limits of SR 3.6.2.1. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits due to the large margin between the air lock leakage and the containment overall leakage acceptance criteria.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour. Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which are applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.2 (continued)

outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the airlock.

REFERENCES

1. USAR, Chapter 14.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated power operated valves secured in their closed position, check valves with flow through the valve secured, blind flanges, and closed systems are considered passive devices. Automatic valves designed to close without operator action following an accident are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system which means it penetrates primary containment, is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere, and has a low probability of being ruptured by an accident (Refs. 1 and 2). These barriers (typically containment isolation valves) make up the Containment Isolation System.

The Containment Isolation System is designed to provide isolation capability following a design basis accident (DBA) for fluid lines which penetrate containment. Major non-essential lines (i.e., fluid systems which do not perform an immediate accident mitigation function) which penetrate containment, except for main steam lines, are either automatically isolated following an accident or are normally maintained closed in MODES 1, 2, 3, and 4. Automatic containment isolation valves are designed to close on a containment isolation signal which is generated by either an automatic safety injection (SI) signal or by manual actuation. The Containment Isolation System can also isolate essential lines at the discretion of

BASES

BACKGROUND (continued)

the operators depending on the accident progression and mitigation requirements.

Upon receipt of a containment pressure High-High signal, both main steam isolation valves close which also causes the instrument air line to containment to isolate if a containment isolation signal is also present. In addition to the isolation signals listed above, the containment purge and inservice purge supply and exhaust line valves and dampers receive isolation signals on a safety injection signal, a containment high radiation condition, a manual containment isolation actuation and manual containment spray initiation. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the outside environment in the event of a release of fission product radioactivity to the containment atmosphere resulting from a DBA.

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

BASES

BACKGROUND (continued)

In addition to the normal fluid systems which penetrate containment, two systems which can provide direct access from inside containment to the outside environment are described below.

Containment Purge System (36 inch purge valves)

The Containment Purge System operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access in MODES 5 and 6. The supply and exhaust lines each contain one isolation valve, one isolation damper and a blind flange. The 36 inch purge valves and dampers are not tested to verify their leakage rate is within the acceptance criteria of the Containment Leakage Rate Testing Program. Therefore, blind flanges are installed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Inservice Purge System (18 inch purge valves)

The Inservice Purge System operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access in MODES 5 and 6.

Two containment automatic isolation valves and an automatic shield building ventilation damper are provided on each supply and exhaust line. The 18 inch purge valves and dampers are not tested to verify their leakage rate is within the acceptance criteria of the Containment Leakage Rate Testing Program. Therefore, blind flanges are installed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

BASES

BACKGROUND

Inservice Purge System (18 inch purge valves) (continued)

The blind flanges are installed on penetrations 42B and 43A (52 and 53 in Unit 2) and tested to meet the acceptance criteria of the Containment Leakage Rate Testing Program.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material to the containment atmosphere are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 3). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves are minimized. The safety analyses assume that the 36 inch purge lines and 18 inch inservice purge lines are blind flanged at event initiation.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In calculation of control room and offsite doses following a LOCA, the accident analyses assume the release timing and radionuclide composition specified for the Alternative Source Term Analyses in Regulatory Guide 1.183 (Ref. 3). The containment is assumed to leak at the maximum allowable leakage rate, L_a, for the first 24 hours of the accident and at 50% of this leakage rate for the remaining duration of the accident.

The containment penetration isolation valves ensure that the containment leakage rate remains below L_a by automatically isolating penetrations that do not serve post accident functions and providing isolation capability for penetrations associated with Engineered Safety Features. The maximum isolation time for automatic containment isolation valves is 60 seconds. This isolation time is based on engineering judgment since the control room and offsite dose calculations are performed assuming that leakage from containment begins immediately following the accident with no credit for transport time or radioactive decay. The 60 second isolation time takes into consideration the time required to drain piping of fluid which can provide an initial containment isolation before the containment isolation valves are required to close and the conservative assumptions with respect to core damage occurring immediately following the accident.

The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Containment isolation also isolates the Reactor Coolant System (RCS) to prevent the release of radioactive material. However, RCS isolation, not isolation of containment, is required for events which result in failed fuel and do not breach the integrity of the RCS (e.g., reactor coolant pump locked rotor). The isolation of containment following these events also isolates the RCS from all non-essential systems to prevent the release of radioactive material outside the RCS. The containment isolation time requirements for these events are bounded by those for the LOCA.

The Containment Isolation System is designed to provide two boundaries for each penetration such that no single credible failure or malfunction (expected fault condition) occurring in any active system component can result in loss of isolation or intolerable leakage in compliance with the AEC GDC 53, “Containment Isolation Valves,” (Ref. 4).

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The containment isolation devices covered by this LCO consist of isolation valves (manual valves, check valves, air operated valves, and motor operated valves), pipe and end caps, closed systems, and blind flanges.

BASES

LCO (continued)

Vent and drain valves located between two isolation devices are also containment isolation devices. Test connections located between two isolation valves are similar to vent and drain lines except that no valve may exist in the test line. A cap or blind flange, as applicable, must be installed on these vent, drain and test lines. A cap or blind flange installed on these lines make them “otherwise secured” for SR considerations.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 36 inch purge valves and 18 inch inservice purge valves must be blind flanged in MODES 1, 2, 3, and 4. The valves covered by this LCO are listed in Reference 2.

The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic power operated valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves/devices are those listed in Reference 2.

Secondary containment (shield building and auxiliary building special ventilation zone) bypass valves must meet additional leakage rate requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, “Containment,” as Type C testing.

This LCO provides assurance that the containment isolation valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by four Notes. The first Note allows penetration flow paths, except for 36 inch containment purge and 18 inch containment inservice purge system penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the blind flanges on the containment purge and containment inservice purge system lines during plant operation, the penetration flow path containing these flanges may not be opened under administrative controls.

Additionally, these administrative controls SHALL only be used for un-isolating the flow path described within the applicable condition; and SHALL NOT be used to breach the containment boundary or opening vent or drain valves within the flow path.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

BASES

ACTIONS (continued)

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event containment isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable, except for secondary containment bypass leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated or mechanically blocked power operated containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no

BASES

ACTIONS

A.1 and A.2 (continued)

longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, except for secondary containment bypass leakage not within limits, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated power operated valve, a closed manual valve, and a blind flange. With the exception of the chemical and volume control system (CVCS), a check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. This required Action does not require any testing or device manipulation. Rather, it involves verification that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements defined in Reference 2. This Note is

BASES

ACTIONS

C.1 and C.2 (continued)

necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1

With the secondary containment bypass leakage rate (SR 3.6.3.8) not within limit, the assumptions of the safety analyses are not met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange.

BASES

ACTIONS

D.1 (continued)

When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration(s) and the relative importance of secondary containment bypass leakage and containment purge penetration valve(s) leakage to the overall containment function.

E.1

In the event containment purge blind flange leakage rate (SR 3.6.3.1) or containment inservice purge blind flange leakage rate (SR 3.6.3.2) are not within limits, the leakage rate must be restored within 1 hour to assure containment leakage rates are met. If containment purge blind flange leakage rate or containment inservice purge blind flange leakage rate limits are not met, it could be due to the blind flange not installed or improperly installed. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABLE during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when blind flange leakage exceeds its limits is minimal.

BASES

ACTIONS (continued)

F.1 and F.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 36 inch containment purge system penetration is required to be blind flanged when the plant is in MODES 1, 2, 3, and 4. This Surveillance is designed to ensure that the blind flange is installed prior to entering MODE 4 from MODE 5.

SR 3.6.3.2

Each 18 inch containment inservice purge penetration is required to be blind flanged when the plant is in MODES 1, 2, 3, and 4. This Surveillance is designed to ensure that the blind flange is installed prior to entering MODE 4 from MODE 5.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those containment manual valves and blind flanges outside containment and capable of being mispositioned are in the correct position. Since verification of manual valve and blind flange position for containment isolation valves outside containment is relatively easy, the 92 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation manual valves and blind flanges inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these containment isolation valves or blind flanges, once they have been verified to be in their proper position, is small.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.3.6

Not used.

SR 3.6.3.7

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.8

This SR ensures that the combined leakage rate of all secondary containment (shield building and auxiliary building special ventilation zone) bypass leakage paths is less than or equal to the specified leakage rate. This provides assurance that the assumptions in the safety analysis are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The acceptance criteria and Frequency are provided by the Containment Leakage Rate Testing Program.

Bypass leakage is considered part of L_a.

REFERENCES

1. 10 CFR 50, Appendix A.

2. USAR, Section 5.2.

3. USAR, Section 14.

4. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 53, issued for comment, July 10, 1967, as referenced in USAR Section 1.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment analyses. Should operation occur outside this limit coincident with a LOCA or SLB, post accident containment pressures could exceed calculated values.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the LOCA and SLB analyses to establish the maximum peak containment internal pressure. The limiting events considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure models. The worst case SLB generates larger mass and energy release than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1). The initial pressure condition used in the containment analysis was 16.7 psia (2.0 psig). This resulted in a maximum peak pressure from a SLB of less than 46 psig. The containment analyses show that the maximum peak calculated containment pressure results from the SLB. The maximum containment pressure resulting from the SLB does not exceed the containment design maximum internal pressure, 46 psig. Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a LOCA or SLB, the resultant peak containment accident pressure will remain below the containment design maximum internal pressure.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3, and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 8 hours. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is greater than the ACTIONS of LCO 3.6.1, “Containment,” which requires that containment be restored to OPERABLE status within 1 hour. However, due to the large containment free volume and limited size of the post-LOCA vent system, 8 hours is allowed to restore containment pressure to within limits. This is justified by the low probability of a DBA during this time period.

BASES

ACTIONS (continued)

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition.

REFERENCES

1. USAR, Section 14.5.

3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Cooling Systems provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a design basis accident (DBA), to within limits. The Containment Spray and Containment Cooling Systems are designed, as described in the USAR, to meet the requirements of AEC GDC 37, "Engineered Safety Features Basis for Design," GDC 38, "Reliability and Testing of Engineered Safety Features," GDC 41, "Engineered Safety Features Performance Capability," GDC 42, "Engineered Safety Features Components Capability," GDC 49, "Containment Design Basis," GDC 52, "Containment Heat Removal Systems," GDC 58, "Inspection of Containment Pressure-Reducing Systems," GDC 59, "Testing of Containment Pressure-Reducing Systems," GDC 60, "Testing of Containment Spray Systems," and GDC 61, "Testing of Operational Sequence of Containment Pressure-Reducing Systems," (Ref. 1).

The Containment Cooling System and Containment Spray System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained.

<u>Containment Spray System</u>

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases.

BASES

BACKGROUND

Containment Spray System (continued)

Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of a DBA.

The Containment Spray System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature and to remove fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System. Each train of the Containment Spray System provides adequate spray coverage to provide 100% of the Containment Spray System design requirements for containment heat removal.

The Spray Additive System mixes an NaOH solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment sump. Controlling the alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. An automatic actuation signal opens the containment spray pump discharge valves, opens the Spray Additive System valves, starts the two containment spray pumps, and begins injection. A manual actuation of the Containment Spray System requires the operator to simultaneously actuate two separate switches on the main control board to begin the

BASES

BACKGROUND

Containment Spray System (continued)

same sequence. The spray injection continues until containment pressure is reduced to less than 20 psig or an RWST level Low-Low alarm is received. When one of these conditions is reached, containment spray is manually terminated.

Due to the nature of the containment spray system, most functional tests are performed with the isolation valves in the spray supply lines at containment and the spray additive tank isolation valves blocked closed. The tests are considered satisfactory if visual observations indicate all components have operated satisfactorily.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply 100% of the Containment Cooling System design cooling requirements, are provided. Each train of two fan coil units is normally supplied with chilled water during summer operation or cooling water from separate trains of the Cooling Water System (CL) for winter or emergency operation. Air is drawn into the coolers through the fan and discharged to the containment atmosphere including various compartments (e.g., steam generator and pressurizer compartments).

During normal operation, all four fan coil units are operating. The fans may be operated at high or low speed with chilled water (summer operation) or CL water supplied to the cooling coils. The Containment Cooling System is designed to limit the ambient containment air temperature during normal unit operation to less than 120°F. This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

BASES

BACKGROUND

Containment Cooling System (continued)

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If running in high speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. The temperature of the cooling water is an important factor in the heat removal capability of the fan coil units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a loss of coolant accident (LOCA) or steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. These events are not assumed to occur simultaneously or consecutively. These postulated events are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analyses and evaluations show that under the worst case scenario, the highest peak containment pressure is less than 46 psig. The analyses show that the peak containment temperature meets the intent of the design basis. The analyses and evaluations assume a conservative unit specific power level for the accident under consideration (LOCA or SLB), one containment spray train and one containment cooling train operating, and conservative initial (pre-accident) containment pressure of 2.0 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures.

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a containment pressure reduction associated with the sudden cooling effect in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.8.

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High-High pressure setpoint to achieving full flow through the containment spray nozzles.

The analyses of the Main Steam Line Break (MSLB) and LOCA incorporated delays in Containment Spray actuation to account for load restoration, discharge valve opening, containment spray pump windup, and spray line filling (Ref. 3).

Containment cooling train performance for post accident conditions is given in Reference 4. The result of the analyses is that one train of containment cooling with one train of containment spray can provide 100% of the required peak cooling capacity during post accident conditions. The train post accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 5.

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with receiving a safety injection (SI) signal to achieving full

BASES

APPLICABLE SAFETY ANALYSES (continued)

Containment Cooling System air and safety grade cooling water flow. The Containment Cooling System total response time incorporates delays to account for load restoration and motor windup (Ref. 3).

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a LOCA or SLB, a minimum of one containment cooling train and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 4). Additionally, one containment spray train is also required to supply sufficient sodium hydroxide to containment to ensure that the pH of the sump liquid is alkaline. To ensure that these requirements are met, two containment spray trains and two containment cooling trains must be OPERABLE. Therefore, in the event of an accident, at least one train in each system operates, assuming the worst case single active failure occurs.

Each Containment Spray System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon a containment spray actuation signal. Manual valves in this system that could, if improperly positioned, reduce the spray flow below that assumed for accident analysis, are blocked and tagged in the proper position and maintained under administrative control. Containment Spray System motor operated valves, MV-32096 and MV-32097 (Unit 1), and MV-32108 and MV-32109 (Unit 2) are closed with the motor control center supply breakers in the off position.

Each Containment Cooling System typically includes cooling coils, dampers, fans, and controls to ensure an OPERABLE flow path. With one CL strainer isolated, the containment cooling train on the associated CL header is OPERABLE at CL supply temperatures

BASES

LCO (continued)

up to and including 70ºF. When the CL supply temperature is above 70ºF with one CL strainer isolated, the containment cooling train on the associated CL header is not OPERABLE. If Technical Specification (TS) 3.6.5 Condition D has been entered, then the above correlation between CL strainer status, CL supply temperature and containment cooling train OPERBILITY is not applicable. In this case the remaining two containment cooling fan coil units provide adequate heat removal within the TS 3.6.5 Condition D allowed Completion Time.

APPLICABILITY

In MODES 1, 2, 3, and 4, a LOCA or SLB could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains and containment cooling trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and the Containment Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the other Containment Spray train, reasonable time for repairs, and low probability of a LOCA or SLB occurring during this period.

The 10 day portion of the Completion Time for Required Action A.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident

BASES

ACTIONS

A.1 (continued)

occurring during this time. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one or both of the containment cooling fan coil units (FCU) in one train inoperable, the inoperable FCU(s) must be restored to OPERABLE status within 7 days. In this degraded condition the remaining OPERABLE containment spray and cooling trains provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System and the low probability of a DBA occurring during this period.

BASES

ACTIONS

C.1 (continued)

The 10 day portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

D.1 and D.2

Condition D applies when one FCU in each train is inoperable. With two FCUs inoperable, the Required Actions are to isolate cooling water flow to both inoperable FCUs immediately. This will assure the containment cooling function continues to be provided.

The LCO requires the OPERABILITY of a number of components within the subsystems. Due to the redundancy of components within the containment cooling system, the inoperability of two FCU does not render the containment cooling system incapable of performing its function. Engineering analyses demonstrate that two OPERABLE FCUs, one in each train, are capable of providing the necessary cooling.

With a FCU inoperable in both containment cooling trains and a FCU OPERABLE in both containment cooling trains, the two remaining OPERABLE FCUs can provide the necessary cooling provided the cooling water flow to the inoperable FCUs is isolated.

When one FCU in each containment cooling train is inoperable, both inoperable FCUs must be restored to OPERABLE status within 7 days. In this degraded condition the remaining OPERABLE containment spray and FCU from each cooling train provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the heat removal capabilities afforded by combinations of the Containment Spray System and Containment

BASES

ACTIONS

D.1 and D.2 (continued)

Cooling System and the low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action D.2 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment (there are no valves inside containment) and capable of potentially being mispositioned are in the correct position.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.2

Operating each containment fan coil unit on low motor speed for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly.

Motor current is measured and compared to the nominal current expected for the test condition. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency was developed considering the known reliability of the fan coil units and controls, the two train redundancy available, and the low probability of significant degradation of the containment cooling train occurring between Surveillances. It has also been shown to be acceptable through operating experience.

SR 3.6.5.3

Verifying that cooling water flow rate to each containment fan coil unit is ≥ 900 gpm provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 4).

Terminal temperatures of each fan coil unit are also observed. This test includes verifying operation of all essential features including low motor speed, cooling water valves and normal ventilation system dampers. The 24 month Frequency is based on; the need to perform these Surveillances under the conditions that apply during a plant outage; the known reliability of the Cooling Water System; the two train redundancy available; and, the low probability of a significant degradation of flow occurring between Surveillances.

SR 3.6.5.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 6). Since the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.4 (continued)

containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.5.5 and SR 3.6.5.6

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High-High pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. To prevent inadvertent spray in containment, containment spray pump testing with a simulated actuation signal will be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. These tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillances when performed. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.7

This SR requires verification that each containment cooling train actuates upon receipt of an actual or simulated safety injection signal. The 24 month Frequency is based on engineering judgment. See SR 3.6.5.5 and SR 3.6.5.6, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.5.8

With the spray header drained, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, confirmation of operability following maintenance activities that can result in obstruction of spray is considered adequate to detect obstruction of the nozzles. Confirmation that the spray nozzles are unobstructed may be obtained by such means as foreign materials exclusion (FME) controls during maintenance, a visual inspection of the affected portions of the system, or by an air or smoke test following maintenance involving opening portions of the system downstream of the containment isolation valves, or by draining and flushing the filled portions of the system inside containment, as appropriate. Maintenance that could result in nozzle blockage is generally a result of a loss of FME control or a flow of borated water through a nozzle. Should either of these events occur, an engineering evaluation will be performed to determine whether nozzle blockage is a possible result of the event.

If loss of FME control occurs, an inspection or flush of the affected portions of the system should be adequate to confirm that the spray nozzles are unobstructed since water flow would be required to transport any debris to the spray nozzles. An air flow or smoke test may be appropriate when borated water has inadvertently flowed through a nozzle.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criteria 37, 38, 41, 42, 49, 52, and 58 through 61 issued for comment July 10, 1967, as referenced in USAR Section 1.2.
2. USAR Section 6.4.
3. USAR, Section 14.5.
4. USAR, Section 6.3.
5. USAR, Section 5.2.
6. American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a design basis accident (DBA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, sodium hydroxide (NaOH) is the spray additive used at Prairie Island. The NaOH added to the spray also ensures a pH value of between 8.5 and 10.5 in the spray and greater than 7.0 in the solution recirculated from the containment sump (Ref. 1). These pH levels minimize the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

The spray additive tank contains at least 2590 gallons of solution with a sodium hydroxide concentration of 9% to 11% by weight.

The Spray Additive System consists of one spray additive tank, two parallel redundant control valves in the line between the additive tank and the containment spray pump suction header, instrumentation, and recirculation pumps. The NaOH solution is added to the spray water by gravity feed at a fixed ratio to the refueling water storage tank (RWST) flow at the suction of the containment spray pumps. Because of the hydrostatic balance between the two tanks, the flow rate of the NaOH is controlled by the volume per foot of height ratio of the two tanks. This ensures a spray mixture pH that is ≥ 8.5 and ≤ 10.5.

BASES

BACKGROUND (continued)

The Containment Spray System actuation signal opens the valves from the spray additive tank to the spray pump suctions. The 9 wt.% to 11 wt.% NaOH solution is drawn into the spray pump suctions. The percent solution and volume of solution sprayed into containment ensures a long term containment sump pH of ≥ 7.0 and ≤ 10.5. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping.

APPLICABLE SAFETY ANALYSES

The Spray Additive System is essential to the removal of airborne iodine within containment following a DBA. Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its licensing basis value volume for the first 24 hours following the accident.

The DBA response time assumed for the Spray Additive System is the same as for the Containment Spray System and is discussed in the Bases for LCO 3.6.5, “Containment Spray and Cooling Systems.”

The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable and that the active spray additive tank volume is added to the remaining Containment Spray System flow path.

The Spray Additive System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. This system provides NaOH which mixes into the spray flow until the end of the injection phase to raise the average spray solution pH to a level conducive to iodine removal, namely, to between 8.5 and 10.5.

BASES

LCO (continued)	This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. The Spray Additive System is considered OPERABLE when: a. The volume of the spray additive solution is ≥ 2590 gal and the concentration is ≥ 9 weight percent and ≤ 11 weight percent; b. Two flow paths from the spray additive tank to the containment spray pump suction header are OPERABLE; c. Manual valves are properly positioned and automatic valves are capable of activating to their correct positions; and d. Piping, valves, instrumentation, and controls for the required flow paths are OPERABLE.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the iodine fission product inventory prior to release to the environment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODE 5 or 6.
ACTIONS	<u>A.1</u> If the Spray Additive System is inoperable, it must be restored to OPERABLE within 24 hours. The pH adjustment of the

BASES

ACTIONS

A.1 (continued)

Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 24 hour Completion Time takes into account the redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Spray Additive System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced driving force in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1 (continued)

prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position.

SR 3.6.6.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The 184 day Frequency was developed based on the low probability of an undetected change in tank volume occurring during the SR interval (the tank is isolated during normal unit operations). Tank level is indicated and alarmed in the control room, so that there is high confidence that a substantial change in level would be detected.

SR 3.6.6.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The 184 day Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 6.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Not Used

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Vacuum Breaker System

BASES

BACKGROUND

The purpose of the Vacuum Breaker System is to protect the containment vessel against negative pressure (i.e., a lower pressure inside than outside). Excessive negative pressure inside containment can occur if there is an inadvertent actuation of containment cooling features, such as the Containment Spray System or Containment Cooling System. Multiple equipment failures or human errors are necessary to cause inadvertent actuation of these systems.

The containment pressure vessel contains two 100% vacuum breaker trains that protect the containment from excessive external loading.

The characteristics of the vacuum breakers and their locations in the containment pressure vessel are as follows:

Two vacuum breakers are used in each of two large vent lines which permit air to flow from the shield building annulus into the reactor containment vessel. The vacuum breakers consist of an air to close, spring loaded to open butterfly valve and a self-actuated horizontally installed, swinging disc check valve. An air accumulator is provided for each of the air-operated vacuum breakers to allow vacuum breaker operation in the event of a loss of instrument air. The vent lines enter the containment vessel through independent and widely separated containment penetration nozzles. The vacuum breakers serve dual functions in that they are also required to isolate containment following an accident if containment becomes pressurized greater than negative 0.2 psid relative to the shield building annulus.

BASES (continued)

APPLICABLE SAFETY ANALYSES

Design of the Vacuum Breaker System involves calculating the effect of inadvertent actuation of containment cooling features, which can reduce the atmospheric temperature (and hence pressure) inside containment (Ref. 1). Conservative assumptions are used for all the relevant parameters in the calculation: for example, for the Containment Spray System, the minimum spray water temperature, maximum initial containment temperature, maximum spray flow, all spray trains operating, all four containment fan units operating with maximum cooling water flow rate with minimum inlet water temperature, etc. The resulting containment pressure versus time is calculated, including the effect of the opening of the vacuum relief lines when their negative pressure setpoint is reached. It is also assumed that one valve fails to open.

The containment shell was designed for an external pressure load equivalent to 0.8 psi greater than the internal pressure. The inadvertent actuation of the containment cooling features was analyzed to determine the resulting reduction in containment pressure. The analysis shows that one vacuum breaker train will terminate this transient before 0.8 psi pressure differential is reached.

The Vacuum Breaker System must also perform the containment isolation function in a containment high pressure event. For this reason, the system is designed to take the full containment positive design pressure and the environmental conditions (temperature, pressure, humidity, radiation, chemical attack, etc.) associated with the containment DBA.

The vacuum relief valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The LCO establishes the minimum equipment required to accomplish the vacuum relief function following the inadvertent actuation of containment cooling features. Two 100% vacuum breaker trains are required to be OPERABLE to ensure that at least one is available, assuming one or both valves in the other line fail to open.

A vacuum breaker train is OPERABLE when both valves, including air supplies, instrumentation, controls, and actuating and power circuits, are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the containment cooling features, such as the Containment Spray System, are required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside containment could occur whenever these systems are required to be OPERABLE due to inadvertent actuation of these systems. Therefore, the vacuum breaker trains are required to be OPERABLE in MODES 1, 2, 3, and 4 to mitigate the effects of inadvertent actuation of the Containment Spray System, or Containment Cooling System.

In MODES 5 and 6, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations of these MODES. The Containment Spray System, and Containment Cooling System are not required to be OPERABLE in MODES 5 and 6. Therefore, maintaining OPERABLE vacuum relief valves is not required in MODE 5 or 6.

BASES (continued)

ACTIONS

A.1 and A.2

When the vacuum relief function of one vacuum breaker train is inoperable, the inoperable train must be restored to OPERABLE status within 7 days. The allowed Completion Time is reasonable considering the redundancy of the other vacuum breaker train, its reliable vacuum relief capability due to the passive design and the low probability of an event requiring use of the Vacuum Breaker System during this time.

B.1 and B.2

If the vacuum breaker train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply.

To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

This SR requires verification that each automatic function of each vacuum breaker train actuates as required to perform its safety function. Testing shall include demonstration that an actual or simulated containment vacuum equal to or less than 0.5 psi will open the air-operated valve and an actual or simulated containment isolation signal with containment pressure greater than negative 0.2 psid relative to the shield building annulus will close the valve. The 92 day Frequency is based on engineering judgment and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)	<u>SR 3.6.8.2</u> This SR requires the performance of a CHANNEL CALIBRATION. A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. Operating experience has shown that these components usually pass the Surveillance when performed.
REFERENCES	1. USAR, Section 5.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Shield Building Ventilation System (SBVS)

BASES

BACKGROUND

As described in the USAR the SBVS is required by AEC GDC 70, “Control of Releases of Radioactivity to the Environment” (Ref. 1), to ensure that radioactive materials that leak from the primary containment into the shield building (secondary containment) following a design basis accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The containment has a secondary containment called the shield building, which is a concrete structure that surrounds the steel primary containment vessel. Between the containment vessel and the shield building inner wall is an annular space that collects a portion of the containment leakage following a loss of coolant accident (LOCA). This space also allows for periodic inspection of the outer surface of the steel containment vessel.

The SBVS establishes a negative pressure in the annulus between the shield building and the steel containment vessel following a DBA. Filters in the system then control the release of radioactive contaminants to the environment. Shield building OPERABILITY is required to ensure retention of primary containment leakage and proper operation of the SBVS.

The SBVS consists of two separate and redundant trains. Each train includes a heater, a prefilter, moisture separators, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of radioiodines, a recirculation fan and an exhaust fan. Ductwork, valves and/or dampers, and instrumentation also form part of the system. The ventilation system for each shield building includes a vent stack which penetrates the shield building dome and discharges to the atmosphere. The moisture separators function to reduce the moisture content of the airstream. The HEPA filter is credited in the analysis. The charcoal adsorber is not credited in the analysis.

BASES

BACKGROUND (continued)

The system initiates and maintains a negative air pressure in the shield building by means of filtered exhaust ventilation of the shield building following receipt of a safety injection (SI) signal. The system is described in Reference 2.

The prefilters remove large particles in the air, and the moisture separators remove entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers. The heaters are designed to dry incoming air at 100% saturation by increasing the temperature of the air entering the charcoal bed.

The SBVS reduces the radioactive content in the shield building atmosphere following a DBA. Loss of the SBVS could cause site boundary doses, in the event of a DBA, to exceed the values given in the licensing basis.

APPLICABLE SAFETY ANALYSES

The SBVS design basis is established by the consequences of the limiting DBA, which is a LOCA. The accident analysis (Ref. 3) assumes that only one train of the SBVS is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the remaining one train of this filtration system. The amount of fission products available for release from containment is determined for a LOCA.

The modeled SBVS actuation in the safety analyses is based upon a worst case response time following an SI initiated at the limiting setpoint. The total response time, from accident initiation to attaining a negative pressure in the shield building, is less than 12 minutes. This response time bounds the signal delay, diesel generator startup and sequencing time, system startup time, and time for the system to attain the required pressure after starting.

The SBVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

In the event of a DBA, one SBVS train is required to provide the minimum particulate iodine removal assumed in the safety analysis. Two trains of the SBVS must be OPERABLE to ensure that at least one train will operate, assuming that the other train is disabled by a single active failure.

A train of SBVS is OPERABLE when its associated:

a. Recirculation and exhaust fan are OPERABLE;

b. HEPA filter is capable of passing the design flow and performing the filtration function;

c. Manual valves and dampers are properly positioned and automatic valves and dampers are capable of activating to their correct positions; and

d. Ductwork, valves, dampers, instrumentation, and controls for the required flow path are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could lead to fission product release to containment that leaks to the shield building. The large break LOCA, on which this system's design is based, is a full power event. Less severe LOCAs and leakage still require the system to be OPERABLE throughout these MODES. The probability and severity of a LOCA decrease as core power and Reactor Coolant System pressure decrease. With the reactor shut down, the probability of release of radioactivity resulting from such an accident is low.

In MODES 5 and 6, the probability and consequences of a DBA are low due to the pressure and temperature limitations in these MODES. Under these conditions, the SBVS is not required to be OPERABLE.

BASES (continued)

ACTIONS

A.1

With one SBVS train inoperable, the inoperable train must be restored to OPERABLE status within 7 days. In this degraded condition, the remaining components are capable of providing 100% of the iodine removal needs after a DBA. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SBVS train and the low probability of a DBA occurring during this period. The Completion Time is adequate to make most repairs.

B.1 and B.2

If the SBVS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

Operation with the heaters on for ≥ 15 minutes demonstrates operability of the system. Periodic operation also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls, the two train redundancy available, and the iodine removal capability of the Containment Spray System.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.9.2

This SR verifies that the required SBVS filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance and minimum system flow rate. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.9.3

The automatic startup ensures that each SBVS train responds properly. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown that these components usually pass the Surveillance when performed. Therefore the Frequency was concluded to be acceptable from a reliability standpoint. Furthermore, the SR interval was developed considering that the SBVS equipment OPERABILITY is demonstrated at a 31 day Frequency by SR 3.6.9.1.

SR 3.6.9.4

The SBVS isolation dampers are tested to verify OPERABILITY. The dampers are in the closed position during normal plant operation and must reposition for accident operation to draw air through the filters. The 24 month Frequency is considered to be acceptable based on damper reliability and design, mild environmental conditions in the vicinity of the dampers, and the fact that operating experience has shown that the dampers usually pass the Surveillance when performed.

BASES (continued)

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 70, issued for comment July 10, 1967, as referenced in USAR Section 1.2.
2. USAR, Section 5.3.
3. USAR, Section 14.9.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.10 Shield Building

BASES

BACKGROUND

The shield building is a concrete structure that surrounds the steel containment vessel. Between the containment vessel and the shield building inner wall is an annular space that collects a portion of the containment leakage that may occur following a design basis accident (DBA). This space also allows for periodic inspection of the outer surface of the steel containment vessel. The shield building provides biological shielding for DBA conditions, protects the containment vessel from low temperatures, adverse atmospheric conditions and external missiles, and provides the means for collecting and filtering containment fission product leakage following a DBA (Ref. 1).

Following a DBA the Shield Building Ventilation System (SBVS) establishes a negative pressure in the annulus between the shield building and the steel containment vessel. Filters in the system then control the release of radioactive contaminants to the environment. The shield building is required to be OPERABLE to ensure retention of containment leakage and proper operation of the SBVS.

APPLICABLE SAFETY ANALYSES

The design basis for shield building OPERABILITY is a loss of coolant accident (LOCA). Maintaining shield building OPERABILITY ensures that the release of radioactive material from the containment atmosphere is restricted to those leakage paths and associated leakage rates assumed in the accident analyses.

The shield building satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

Shield building OPERABILITY must be maintained to ensure proper operation of the SBVS and to limit radioactive leakage

BASES

LCO (continued)

from the containment to those paths and leakage rates assumed in the accident analyses. The shield building is OPERABLE when:

a. At least one door in each access opening is closed including when the access opening is being used for normal transit entry and exit; and

b. The shield building equipment opening is closed.

APPLICABILITY

Maintaining shield building OPERABILITY prevents leakage of radioactive material from the shield building. Radioactive material may enter the shield building from the containment following a DBA. Therefore, shield building OPERABILITY is required in MODES 1, 2, 3, and 4 when a DBA could release radioactive material to the containment atmosphere.

In MODES 5 and 6, the probability and consequences of a DBA are low due to the Reactor Coolant System temperature and pressure limitations in these MODES. Therefore, shield building OPERABILITY is not required in MODE 5 or 6.

ACTIONS

A.1

In the event shield building OPERABILITY is not maintained, shield building OPERABILITY must be restored within 24 hours. Twenty-four hours is a reasonable Completion Time considering the limited leakage design of containment and the low probability of a DBA occurring during this time period.

BASES

ACTIONS (continued)

B.1 and B.2

If the shield building cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.10.1

Maintaining shield building OPERABILITY requires verifying one door in the access opening closed. Each access opening into the shield building contains one inner and one outer door. The intent is to not breach the shield building boundary at any time when the shield building boundary is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times. However, all shield building access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. The 31 day Frequency of this SR is based on engineering judgment and is considered adequate in view of the other indications of door status that are available to the operator.

SR 3.6.10.2

The SBVS produces a negative pressure to prevent leakage from the building. SR 3.6.10.2 verifies that the shield building can be rapidly drawn down to -2.00 inch water gauge and maintains a pressure equal to or more negative than -1.82 inches of water gauge in the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.10.2 (continued)

annulus after the recirculation dampers open and equilibium is established. Equilibrium negative pressure equal to or more negative than -1.82 inches water gauge is that predicted for non-accident conditions and leakage equal to 75% of the maximum allowable shield building inleakage (Reference 2). Establishment of this pressure is confirmed by SR 3.6.10.2, which demonstrates that the shield building can be drawn down to a pressure equal to or more negative than -2.0 inches of water gauge in the annulus using one SBVS train.

The primary purpose of this SR is to ensure shield building integrity. The secondary purpose of this SR is to ensure that the SBVS being tested functions as designed. The inoperability of the SBVS train does not necessarily constitute a failure of this Surveillance relative to the shield building OPERABILITY.

The 31 day Frequency provides assurance that shield building integrity is maintained and the system will function as required.

REFERENCES

1. USAR, Section 5.3.

2. "Report to the United States Nuclear Regulatory Commission Division of Operating Reactors - Prairie Island Containment Systems Special Analyses", dated April 9, 1976.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the USAR (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-1 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine reactor trip.

Normal functioning of a MSSV is expected to involve some "simmering" which does not make the valve inoperable.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis. The accident analysis requires five MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 100.36% RTP.

BASES

APPLICABLE SAFETY ANALYSES (continued)	By relieving steam, the MSSVs prevent RCS overpressurization. The limiting events, described in the USAR (Ref. 3), that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, such as the full power turbine trip without steam dump, and increasing core heat flux events, such as the rod cluster control assembly (RCCA) withdrawal at power. The safety analyses demonstrate that the transient response for turbine trip occurring from full power without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. If a minimum (least negative or most positive) reactivity feedback is assumed, the reactor is tripped on high pressurizer pressure. In this case, the pressurizer safety valves open, and RCS pressure remains below 110% of the design value. The MSSVs also open to limit the secondary steam pressure. The transient response for the slow and fast RCCA withdrawal at power events also present no hazard to the integrity of the RCS or the Main Steam System. Diverse reactor trip inputs from nuclear instrumentation and pressurizer level and pressure are assumed to shut down the reactor when the associated trip setpoint is reached. In this analysis, the pressurizer safety valves open and RCS pressure remains below 110% of the design value. The MSSVs also open to limit the secondary steam pressure. The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requires that five MSSVs per steam generator be OPERABLE in compliance with Reference 2. The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances, relieve steam generator overpressure, and close when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

BASES

LCO (continued)	This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB or Main Steam System integrity.
APPLICABILITY	In MODES 1, 2, and 3, five MSSVs per steam generator are required to be OPERABLE to prevent Main Steam System overpressurization. In MODES 4, 5, and 6, there are no credible transients requiring the MSSVs. The energy content in the steam generators is sufficiently low in MODES 5 and 6 that they cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.
ACTIONS	<u>A.1</u> With one MSSV inoperable, restore OPERABILITY of the inoperable MSSV within 4 hours. The 4 hours is a reasonable time due to the low probability of an event or transient occurring during this time requiring MSSV operation. Continued operation with less than all five MSSVs OPERABLE for each steam generator is not permitted since safety analyses supporting such operation have not been performed. <u>B.1 and B.2</u> If the MSSV cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within

BASES

ACTIONS

B.1 and B.2 (continued)

12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code (Ref. 4), requires that safety and relief valve tests be performed in accordance with Reference 5. According to Reference 5, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-1 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to within a nominal ± 1% of their setpoint during the Surveillance. The lift settings, according to Table 3.7.1-1, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. USAR, Section 11.4.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.
3. USAR, Section 14.4.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.
5. ASME OM Code, Appendix I, Inservice Testing of Pressure Relief Devices in Light-Water Reactor Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a main steam line break (MSLB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the other, and isolates the turbine, Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam isolation signal generated by any of the following signals:

a. High-High Containment Pressure;

b. High Steam Flow and Low-Low T_{avg} with Safety Injection; and

c. High-High Steam Flow with Safety Injection.

The MSIVs fail closed on loss of air.

Each MSIV has a MSIV bypass valve. These valves are normally used for warming steam lines and equalizing pressure across the MSIVs. These bypass valves are normally closed at power.

The MSIVs and MSIV bypass valves may be operated manually.

BASES

BACKGROUND (continued)

In addition to the fast-closing stop valve, each steam line has a downstream non-return check valve (NRCV). The four valves (one MSIV and one NRCV in each of two lines) prevent blowdown of more than one steam generator for any break location even if one valve fails to close. A description of the MSIVs and NRCVs is found in the USAR (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the USAR (Ref. 2). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV or NRCV to close).

The limiting pressure case for the containment analysis is the main steam line break (MSLB) inside containment at 30% power, with offsite power available following turbine trip, and failure of a safeguards train. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The analysis of several different SLB events are performed to demonstrate that the acceptance criteria listed in the USAR are satisfied.

Events evaluated include:

a. Containment response due to a large SLB inside of containment;

b. Core response due to a large SLB inside of containment; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Small SLB.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. A MSLB inside containment. For this accident scenario, steam is discharged into containment from both steam generators until the NRCV on the broken line (or MSIV on the intact line) closes. After the valve closes, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header between the closed valve and the affected steam generator. Closure of the NRCV in the affected line (or the MSIV in the intact line) isolates the break from the unaffected steam generator.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the NRCV in the affected line (or the MSIV in the intact line) isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIV downstream of the ruptured steam generator isolates the ruptured steam generator from the intact steam generator to minimize radiological releases.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

This LCO requires that both MSIVs be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on a main steam isolation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally the MSIVs are closed, and the steam generator energy is low. In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs and considering the redundancy of the NRCV.

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional passive means for containment isolation.

BASES

ACTIONS (continued)

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition C would be entered unless both MSIVs are closed. The Completion Times are reasonable, based on operating experience, to reach MODE 2 in an orderly manner without challenging unit systems.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIV may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition A for one MSIV inoperable.

For an inoperable MSIV that cannot be restored to OPERABLE status within the specified Completion Time, but is closed, the inoperable MSIV must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

BASES

ACTIONS (continued)

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that the closure time of each MSIV is within the limit given in Reference 5 and is within that assumed in the accident and containment analyses. This SR also verifies the valve closure time is in accordance with the Inservice Testing Program. This SR is normally performed upon returning the unit to operation following a refueling outage. The MSIVs should not be tested at power, since even a part stroke exercise increases the risk of valve closure when the unit is generating power. As the MSIVs are not tested at power, they are deferred from the ASME Code (Ref. 6) requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

This test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.2

This SR verifies each MSIV can close on an actual or simulated main steam isolation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Frequency of MSIV testing is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 11.7.
2. USAR, Section 14.5.
3. Not used.
4. 10 CFR 100.11.
5. Technical Requirements Manual.
6. ASME Code for Operation and Maintenance of Nuclear Plants.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Regulation Valves (MFRVs) and MFRV Bypass Valves

BASES

BACKGROUND

The MFRVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a steam or feedwater line break. The key safety-significant functions of the MFRVs are to prevent:

a. Overfill of the steam generators;

b. Excessive cooldown of the Reactor Coolant System; and

c. Overpressurization of the containment following a main feedwater line break (FWLB) or main steam line break (MSLB).

Closure of the MFRVs and associated bypass valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring downstream of the main feedwater isolation valves (MFIVs) or MFRVs. Credit is taken for only the MFRVs and the MFRV bypass valves since the closure times are shorter than those of the MFIVs. The MFIVs are treated solely as containment isolation valves in accordance with LCO 3.6.3, “Containment Isolation Valves”. Check valves in the feedwater lines terminate FWLBs upstream of the MFIVs and MFRVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFRVs will be mitigated by their closure. Closure of the MFRVs and MFRV bypass valves effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFRVs, MFRV bypass valves, and piping upstream of the MFIVs are nonsafety related. In the event of a secondary side pipe rupture inside containment, the MFRVs, MFRV bypass valves,

BASES

BACKGROUND (continued)

check valves and the main feedwater pump trip limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFRV and its MFRV bypass valve are located on each MFW line, outside but close to containment. The check valves are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFIV or MFRV closure. The piping volume from the valves to the steam generators must be accounted for in calculating mass and energy releases. This line must be refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

The MFRVs and MFRV bypass valves close due to the following automatic feedwater isolation (FWI) signals:

a. Low T_{avg} coincident with reactor trip (P-4) (MFRV only);

b. Steam generator water level-high high signal; and

c. Safety injection.

The MFRVs and MFRV bypass valves may also be operated manually.

In addition to the MFIVs, the MFRVs and MFRV bypass valves, a check valve inside containment is available. The check valve isolates the feedwater line, penetrating containment, and ensures that the consequences of events do not exceed the capacity of the containment heat removal systems.

A description of the MFRVs is found in the USAR (Ref. 1).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the MFRVs is established by the analyses for the large Main Steam Line Break (MSLB). Closure of the MFRVs and associated bypass valves, and trip of the main feedwater pumps may be relied on to terminate feedwater flow during a MSLB for the containment response analyses.

The MSLB core and containment response analyses bound the accident analysis for the large FWLB. Some leakage through the MFRVs and associated bypass valves is anticipated when control board instrumentation indicates that the valves have closed. This leakage has been conservatively bounded by the MSLB containment analyses.

Failure of a MFRV or the MFRV bypass valves to close following a MSLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following a MSLB or FWLB event.

The MFRVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the MFRVs and the MFRV bypass valves will isolate MFW flow to the steam generators, following a FWLB or MSLB.

This LCO requires that two MFRVs and associated MFRV bypass valves be OPERABLE. The MFRVs and the associated MFRV bypass valves are considered OPERABLE when feedwater isolation times are within limits and they close on a FWI signal. When control board instrumentation indicates that these valves have fully closed, the valves are OPERABLE since leakage through the closed valves has been conservatively bounded by the MSLB analyses, and therefore, they are performing their safety function.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or

BASES

LCO (continued)

FWLB inside containment. Since a feedwater isolation signal on high steam generator level is relied on to terminate an excess feedwater flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFRVs and the MFRV bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. In MODES 1, 2, and 3, the MFRVs and the MFRV bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed, they are already performing their safety function.

In MODES 4, 5, and 6, steam generator energy is low. In addition, the MFRVs and the MFRV bypass valves are normally closed since MFW is not required.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

<u>A.1 and A.2</u>

With one MFRV in one or both flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close and place in manual or to isolate flow through inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function. Similarly, if the feedwater flow path to containment is isolated using, as an example, the MFIV, the required safety function is being met.

BASES

ACTIONS

A.1 and A.2 (continued)

The 72 hour Completion Time takes into account the redundancy afforded by the remaining valves in the feedwater line and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRVs, that are closed and in manual or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

B.1 and B.2

With one MFRV bypass valve in one or both flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close and place in manual or to isolate flow through inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function. Similarly, if the feedwater flow path to containment is isolated using, as an example, the MFIV, the required safety function is being met.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining valves in the feedwater line and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

BASES

ACTIONS

B.1 and B.2 (continued)

Inoperable MFRV bypass valves that are closed and placed in manual or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

C.1 and C.2

If the MFRV(s) or the MFRV bypass valve(s) cannot be restored to OPERABLE status, closed, isolated, or the flow path through the valve isolated within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFRV and MFRV bypass valve is within limits set by the Inservice Testing Program. The MFRV isolation times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. This is consistent with the ASME Code (Ref. 2) periodic stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.2

This SR verifies that each MFRV and MFRV bypass valve can close on an actual or simulated FWI signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Frequency for this SR is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 11.9.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.4 Steam Generator (SG) Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The SG PORVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Steam Dump System to the condenser be unavailable, as discussed in the USAR (Ref. 1). Cooldown is performed in conjunction with the Auxiliary Feedwater System providing makeup water to the steam generators.

One SG PORV line is provided for each steam generator. Each SG PORV line consists of one SG PORV and an associated block valve.

The upstream manual block valves permit SG PORV testing at power and provide an alternate means of isolation. The SG PORVs are equipped with pneumatic controllers to permit control of the cooldown rate.

A description of the SG PORVs is found in References 1 and 2.

APPLICABLE SAFETY ANALYSES

Automatic operation of the SG PORVs is not credited in the safety analyses. Rather, the SG PORVs may provide mitigation for accidents involving use of main steam safety valves.

In the steam generator tube rupture (SGTR) accident analysis presented in Reference 2, the SG PORV in the unaffected steam generator is assumed to be used by the operator to cool down the unit for accidents accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a SGTR event, the operator is required to perform a limited cooldown to establish adequate subcooling as a necessary

BASES

APPLICABLE SAFETY ANALYSES (continued)	step prior to terminating the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for a SGTR is more critical than the time required to cool down for this event and also for other accidents. The SG PORVs are equipped with manual block valves in the event a SG PORV spuriously fails open or fails to close during use. The SG PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two SG PORV lines are required to be OPERABLE to ensure that at least one SG PORV is available to conduct a unit cooldown following a SGTR. Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an event in which the condenser is unavailable for use with the Steam Dump System. A SG PORV is considered OPERABLE when it is capable of being remotely operated and when its associated block valve is open.
APPLICABILITY	In MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal, the SG PORVs are required to be OPERABLE. In MODE 5 or 6, a SGTR is not a credible event.

BASES (continued)

ACTIONS

A.1

With one required SG PORV line inoperable, action must be taken to restore OPERABLE status within 7 days.

The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE SG PORV lines, Steam Dump System, and MSSVs.

B.1

With two SG PORV lines inoperable, action must be taken to restore one SG PORV to OPERABLE status. Since the block valve can be closed to isolate a SG PORV, some repairs may be possible with the unit at power.

The 1 hour Completion Time allows time to plan an orderly shutdown of the unit and is reasonable, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the SG PORV lines.

C.1 and C.2

If the SG PORV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 12 hours.

BASES

ACTIONS

C.1 and C.2 (continued)

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR ensures that the SG PORVs are tested through a full control cycle in accordance with the Inservice Testing Program. The SG PORV is isolated by the block valve for this test. Performance of inservice testing or use of a SG PORV during a unit cooldown may satisfy this requirement.

Operating experience has shown that these components usually pass the Surveillance when performed in accordance with the Inservice Testing Program. The Frequency is acceptable from a reliability standpoint.

SR 3.7.4.2

The function of the block valve is to isolate a failed open SG PORV. Manually cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement.

Operating experience has shown that these components usually pass the Surveillance when performed. The Frequency is acceptable from a reliability standpoint.

BASES (continued)

REFERENCES	1.	USAR, Section 11.4.
	2.	USAR, Section 14.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply.

The AFW system is configured into two redundant trains. One train has a turbine driven AFW pump; the other has a motor driven AFW pump. Each AFW pump feeds the designated unit's two steam generators. In addition, each motor driven pump has the capability to be realigned locally to feed the other unit's steam generators.

The AFW pumps take suction from:

a. The nonsafety-related condensate storage tank (CST) supply header (LCO 3.7.6); or

b. The safety-related Cooling Water System (LCO 3.7.8).

The AFW pumps supply water to the steam generator secondary side via connections to the main feedwater (MFW) piping adjacent to the steam generators inside containment.

The steam generators function as a heat sink for core decay heat. The heat load may be dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1), steam generator power operated relief valves (SG PORVs) (LCO 3.7.4), or steam dump valve.

If the main condenser is available, steam may be released via the steam dump valve. Each unit's AFW System consists of:

BASES

BACKGROUND (continued)

a. One motor driven AFW pump;

b. One turbine driven AFW pump;

c. Steam generator AFW motor-operated supply valves; and

d. Steam generator AFW motor-operated throttle valves.

These components are configured to provide a flow path from each pump to both steam generators for the specific unit.

Each motor driven or turbine driven AFW pump can provide 100% of the required AFW flow capacity to the steam generators, as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system.

The turbine driven AFW pump receives steam from both main steam lines upstream of the main steam isolation valves. Each steam feed line will supply 100% of the requirements of the turbine driven AFW pump. An air operated valve downstream of the motor operated valves from each loop allows passage of steam to the turbine driven AFW pump when required. The air supply to the valve is controlled by a normally open DC solenoid valve designed such that failure of either the air supply or control power would cause the respective valve to open, starting the turbine driven AFW pump. Additionally, the air operated steam supply valve has a safety function to close on turbine driven AFW pump low suction or discharge pressure, which results in tripping the turbine driven AFW pump.

The AFW System is capable of supplying feedwater to the steam generators during normal unit operation in MODES 2 and 3. One pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions.

The AFW System is designed to supply sufficient water to the steam

BASES

BACKGROUND (continued)	generators to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steamreleased through the SG PORVs or steam dump valve.

The following safety signals automatically initiate an AFW pump start signal:

a. Low-low water level in either steam generator; and

b. Safety injection.

Additionally, the following signals initiate an AFW pump start signal:

a. Trip of both main feedwater pumps (bypassed during startup and shutdown operation);

b. Loss of both 4 kV normal buses (turbine driven AFW pump only); and

c. Manually either local or remote.

Depending on pump type, the motor will start or the turbine steam admission air operated control valve will open.

The AFW System is discussed in the USAR (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event involving loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus margin for uncertainty and accumulation.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting plant condition which imposes safety-related performance requirements on the design of the AFW System is the loss of MFW as described in References 1 and 3.

The low-low steam generator level signal automatically actuates the motor and turbine driven AFW pumps and associated air operated valve and controls when required to ensure an adequate feedwater supply to the steam generators during loss of offsite power. Normally open motor operated valves are provided for each AFW line to allow throttling of the AFW flow from each AFW pump to each steam generator when required.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

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

Two independent AFW pumps in two diverse trains are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of main feedwater and a single failure.

The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that one motor driven AFW pump be OPERABLE and capable of supplying AFW to both steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to both steam generators. The piping, valves, instrumentation, and controls in the required flow paths, required for

LCO (continued)

the system to perform the safety related function, also are required to be OPERABLE. The normal (Condensate Storage Tanks (CSTs)) and backup (Cooling Water System) water supplies to the AFW pumps must also be OPERABLE. OPERABILITY requirements for the CSTs are specified in LCO 3.7.6, "Condensate Storage Tanks (CSTs)."

Manual valves that could, if improperly positioned, reduce flow below that assumed for accident analysis, are locked in the proper position for emergency use. During MODE 1, changes in these valves' positions will be under direct administrative control. The condensate supply cross connect valve, C-41-2, to the AFW pumps is blocked and tagged open. Changes in position of this valve must be under direct administrative control.

A block is a device that can be unclipped or unsnapped to allow a status change of the component to which it is applied. A lock is a device that must be unlocked, destroyed or mechanically removed (such as a cap or blank) to allow a status change of the component to which it is applied.

The LCO is modified by two Notes. The first Note indicating that an AFW train may be considered OPERABLE during alignment and operation for steam generator level control if capable of being manually realigned to the AFW mode of operation. The second Note indicating that an AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. This is because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.

During operation in MODES 2 and 3, the AFW pump discharge motor operated valves used for throttling may be less than full open. The Shutdown-Auto mode of control may be used during such operations. This control mode bypasses the AFW pump start due to both MFW pumps being tripped or shutdown.

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to provide heat removal. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the AFW System may be used for heat removal via the steam generators.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required to perform a safety function.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If one of the two steam supplies to the turbine driven AFW train is inoperable, or if a turbine driven pump is inoperable while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of a steam supply to the turbine driven AFW pump, the 7 day Completion Time is reasonable since there is a redundant steam supply line for the turbine driven pump;

BASES

ACTIONS

A.1 (continued)

b. For the inoperability of a turbine driven AFW pump while in MODE 3 immediately subsequent to a refueling outage, the 7 day Completion Time is reasonable due to the minimal decay heat levels in this situation; and

c. For both the inoperability of a steam supply line to the turbine driven pump and an inoperable turbine driven AFW pump while in MODE 3 immediately following a refueling outage, the 7 day Completion Time is reasonable due to the availability of the redundant OPERABLE motor driven AFW pump, and due to the low probability of an event requiring the use of the turbine driven AFW pump.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

Condition A is modified by a Note which limits the applicability of the Condition when the unit has not entered MODE 2 following a refueling. Condition A allows one AFW train to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

BASES

ACTIONS (continued)

B.1

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS

C.1 and C.2 (continued)

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

D.1

If both AFW trains are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

E.1

In MODE 4, either the reactor coolant pumps or the RHR Loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, “RCS Loops-MODE 4.” With one required AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths thereby providing assurance that the proper flow paths will exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

This SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during MODES 2, 3, and 4 operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Differential pressure is a normal test of centrifugal pump performance required by the ASME Code (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 2) satisfies this requirement. The Inservice Testing Program specifies the Frequency for testing each pump. This test is considered satisfactory if control board indication and subsequent visual observation of the equipment demonstrate that all components have operated properly.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. This deferral is based on the inservice testing requirements not met; all other requirements for OPERABILITY must be satisfied.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated safety injection signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. This test is considered satisfactory if control board indication and subsequent visual observation of the equipment demonstrate that all components have operated properly. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

This SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during MODES 2, 3, and 4 operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4

This SR verifies that the AFW pumps will start when required by demonstrating that each AFW pump starts automatically on an actual or simulated AFW pump start signal. This test may be performed in a series of sequential, overlapping steps. If portions of this test are performed during unit shutdown, the turbine driven AFW pump is not actually started during unit shutdown, but the components necessary to assure it starts on an actual or simulated AFW pump start signal are demonstrated to be OPERABLE. The pump is started when sufficient steam pressure to perform the test exists. This test is considered satisfactory if control board indication and subsequent visual observation of the equipment demonstrate that all components have operated properly. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the turbine driven AFW pump test. Note 2 states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during MODES 2, 3, and 4 operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

BASES (continued)

REFERENCES

1. USAR, Section 11.9.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants.
3. USAR, Section 14.4.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tanks (CSTs)

BASES

BACKGROUND

Three 150,000 gallon CSTs (total) are shared via a common header between the 2 units. Unit 1 has 1 tank (11) and Unit 2 has 2 tanks (21 and 22). The CSTs provide a nonsafety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS).

A backup safety grade source of water is provided by the safety-related portion of the Cooling Water (CL) System (LCO 3.7.8) via either the Emergency Cooling Water Line or the emergency bay sluice gates.

Since water supplied from the CL System is of lower purity, its use is considered less desirable under normal conditions than the higher purity condensate water from the CSTs. However, if needed, the operator can lineup the Cooling Water supply by opening the associated CL supply motor operated valve (MOV) and closing the associated CST supply MOV for each auxiliary feedwater pump.

The CSTs provide a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves, the steam generator power operated relief valves or the atmospheric dump valve. Each AFW pump operates with a continuous recirculation to a CST.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam dump valve. The condensed steam may be returned to the CSTs by the condensate pump. This has the advantage of conserving condensate while minimizing releases to the environment.

BASES

BACKGROUND (continued)

Although the CSTs are a principal secondary side water source for removing residual heat from the RCS, they are not designed to withstand earthquakes and other natural phenomena, including missiles that might be generated by natural phenomena. However, the backup CL safety-related source is designed to withstand such phenomena.

A description of the CSTs is found in the USAR (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CSTs may provide high purity cooling water to remove decay heat and to cool down the unit following events in the accident analysis as discussed in the USAR (Ref. 2).

The 100,000 gallon CSTs useable volume requirement for each unit in MODE 1, 2, or 3 is sufficient to:

a. Remove the decay heat generated by one reactor in the first 12 hours after shutdown;

b. Ensure sufficient water is available to cool down a reactor from 547°F to 350°F using natural circulation at 25°F/hour; or

c. Ensure sufficient water is available to hold the unit in MODE 3 for 2 hours, followed by a cooldown to RHR entry conditions within the next 6 hours.

These calculations take into account the decay heat and reactor coolant system stored energy (Ref. 1).

The CST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The CSTs are considered OPERABLE when the CSTs' contents have at least 100,000 useable gallons per operating unit (MODES 1, 2, or 3).

This basis is established in Reference 2 and exceeds the volume required by the accident analysis.

The OPERABILITY of the CSTs is determined by maintaining the tank level at or above the minimum required level.

APPLICABILITY

In MODES 1, 2, and 3, and MODE 4, when steam generator is being relied upon for heat removal, the CSTs are required to be OPERABLE.

In MODE 5 or 6, the CSTs are not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the CSTs are not OPERABLE (e.g., level is not within limits), the OPERABILITY of the backup safety-related portion of the CL supply should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup safety-related portion of the CL supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE in accordance with LCO 3.7.8. The CSTs must be restored to OPERABLE status within 7 days.

The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup safety-related portion of the Cooling Water supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup

BASES

ACTIONS

A.1 and A.2 (continued)

safety-related portion of the CL supply being available, and the low probability of an event occurring during this time period requiring the CSTs.

B.1 and B.2

If the CSTs cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply.

To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CSTs contain the required useable volume of cooling water. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks.

Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator of abnormal deviations in the CST level.

BASES (continued)

REFERENCES

1. USAR, Section 11.9.
2. USAR, Section 14.4.

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CC) System

BASES

BACKGROUND

The CC System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CC System also provides this function for various nonessential components, as well as the spent fuel storage pool. The CC System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Cooling Water System, and thus to the environment.

Each unit's CC System is arranged as two parallel cooling loops, and has isolable nonsafety related components. Each safety related train includes a full capacity pump, supply from a common unit-specific surge tank, heat exchanger, piping, valves, and instrumentation.

The CC systems have the capability to be cross-connected between loops and between the two units at the CC pump suction and discharge. This design feature is not used during normal operation but does allow added flexibility of pump and heat exchanger combinations during abnormal conditions.

During operation the outlet CC temperature from the CC heat exchanger is normally maintained between 80°F and 105°F. During operation CC water is circulated through the shell side of the CC heat exchanger and then to the various system components at a maximum temperature of 120°F for 2 hours (Ref. 1).

Each safety related train is powered from a separate bus. A surge tank in the system is provided to ensure that sufficient net positive suction head is available. The pump in each train is automatically started on receipt of a safety injection signal, and all nonessential

BASES

BACKROUND (continued)	components are isolated. In addition, an automatic low pressure pump start can avert a reactor coolant pump seal failure during a loss of offsite power event (Ref. 1). Additional information on the design and operation of the system, along with a list of the components served, is presented in the USAR (Ref. 1). The principal safety related function of the CC System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System during post accident containment sump recirculation.
APPLICABLE SAFETY ANALYSES	The design basis of the CC System is for one CC train to remove the post loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase. During an accident, a design cooling water system (CL) inlet temperature to the CC heat exchanger of 95°F was assumed. CC temperatures are then determined based on this CL inlet temperature. The RHR heat exchanger during DBA long-term conditions is the primary heat load. The required post accident heat removal rate is in the same range as the required rate during MODES 1 or 2, but less than that needed during normal MODE 4 condition. In a normal MODE 4 cooldown from 350°F to 200°F, more equipment is expected to be operating than during a post accident condition or cooldown. The time required to cool from 350°F to 200°F is a function of the number of CC and RHR trains operating (Ref. 1). The CC System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power. One CC train is sufficient to remove decay heat during subsequent operations. The CC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The CC trains are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CC train is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two trains of CC must be OPERABLE. At least one CC train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

A CC train is considered OPERABLE when:

a. The pump and associated surge tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety related function are OPERABLE.

The isolation of CC from other components or systems may render those components or systems inoperable but does not affect the OPERABILITY of the CC System.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CC System is a normally operating system, which must be prepared to perform its post accident safety functions, including but not limited to RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CC System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6,

BASES

ACTIONS

A.1 (continued)

"RCS Loops-MODE 4," be entered if an inoperable CC train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CC train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CC train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CC train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CC flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CC System.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1 (continued)

This SR verifies the correct alignment for manual, air operated, and automatic valves in the CC flow path. This provides assurance that the proper flow paths exist for CC operation.

This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. Control room indication may be used to fulfill this SR.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.7.2

This SR verifies proper automatic operation of the CC valves on an actual or simulated safety injection actuation signal.

The CC System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. This test is considered satisfactory if control board indication and visual observation of the equipment demonstrate that all components have operated properly.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.2 (continued)

The 24 month Frequency is based on engineering judgement and to allow performance of this Surveillance under the conditions that apply during a unit outage. Although this SR may be performed during normal power operation, there may be plant conditions when it is advantageous to perform this Surveillance during a unit outage.

Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note stating that the SR applies to those valves required to align CC System to support the safety injection or recirculation phases of emergency core cooling.

SR 3.7.7.3

The CC pumps may be actuated by either a safety injection signal or system low pressure. This SR verifies proper automatic operation of the CC pumps on an actual or simulated safety injection actuation signal and verifies proper automatic operation of the CC pumps on an actual or simulated low pressure actuation signal. This test is considered satisfactory if control board indication and visual observation of the equipment demonstrate that all components have operated properly.

The CC System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation.

The 24 month Frequency is based on engineering judgement and to allow performance of this Surveillance under the conditions that apply during a unit outage. Although this SR may be performed during normal power operation, there may be plant conditions when it is advantageous to perform this Surveillance during a unit outage.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.7.3 (continued) Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, the Frequency is acceptable from a reliability standpoint.
REFERENCES	1. USAR, Section 10.4.

B 3.7 PLANT SYSTEMS

B 3.7.8 Cooling Water (CL) System

BASES

BACKGROUND

The CL System is a shared system common to both units. The CL System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the CL System also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The CL System consists of a common CL pump discharge header for the five CL (2 nonsafeguards, 2 safeguards, 1 that can be designated as safeguards or nonsafeguards) pumps that directs flow into two separate, 100% capacity, CL headers. Each header then supplies loops in the turbine and auxiliary buildings and containments for the two units.

Each safeguards CL train consists of:

a. One 100% capacity vertical safeguards pump (12 or 121 for Train A; 22 or 121 for Train B);

b. A header; and

c. Piping, valving, instrumentation and controls.

The vertical motor driven pump (121) may be directed to supply either CL header when aligned in its safeguards mode of operation. In this case, the vertical motor driven pump (121) may replace a vertical diesel driven pump.

The vertical motor driven pump may be powered from a pre-selected independent power source (one of the Unit 2 redundant

BASES

BACKGROUND (continued)

safeguards 4 kV buses and associated diesel generator, i.e., 121 CL pump can be aligned to fulfill a Train A or Train B function).

A single CL pump can provide sufficient cooling in one unit during the injection and recirculation phases of a postulated loss of coolant accident plus sufficient cooling to maintain the second unit in a safe shutdown condition.

The CL pump discharge header contains redundant motor-operated header isolation valves (MV-32034, MV-32035, MV-32036, and MV-32037) that assure at least one OPERABLE safeguards pump is aligned to each safeguards supply header when functioning under accident conditions.

The safeguards diesel driven pumps and the vertical motor driven pump (when aligned in the safeguards mode) supply the safeguards components after being automatically started upon receipt of a safety injection or header low pressure signal.

Principal post accident heat loads supplied by the CL System include Unit 1 diesel generators, control room chillers, component cooling (CC) heat exchangers, containment fan coil units, and the nonsafeguards instrument air compressors.

The cooling water supplied to all safeguards and nonsafeguards equipment from supply header A is normally discharged through the Train A CL return header to the Unit 1 Circulating Water (CW) return header. The cooling water supplied to all safeguards and nonsafeguards equipment from supply header B is normally returned through the Train B CL return header to the Unit 2 CW discharge header. The auxiliary feed pumps, safeguards traveling screens, and filtered water supplies do not have return lines.

The two CL return headers are connected through two normally closed, motor-operated isolation valves. An emergency dump to

BASES

BACKGROUND (continued)

grade is connected between the isolation valves. The dump to grade requires manual actuation of the motor valve, either locally or from the main control room. Each of the return headers discharges to a standpipe in the turbine building which directs the cooling water to the CW discharge piping. Each of the standpipes is equipped with an overflow line to the ground outside the turbine building.

The CL System also provides the backup safeguards water supply to the Auxiliary Feedwater System (LCO 3.7.5).

The CL System, in conjunction with the CC System, also cools the unit from residual heat removal (RHR) entry conditions to MODE 5 during normal and post accident operations, as discussed in the USAR (Ref. 1). The time required for this evolution is a function of the number of CC and RHR System trains that are operating. One CL train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6.

Additional information about the design and operation of the CL System, along with a list of the components served, is presented in the USAR (Refs. 1 and 2).

APPLICABLE SAFETY ANALYSES

The design basis of the CL System is to maintain cooling for the heat loads of one unit in MODE 3 and the second unit in long term post accident condition.

One CL train, in conjunction with the CC System and a 100% capacity containment cooling system, has the capability to remove long term core decay heat following a design basis LOCA as discussed in the USAR (Ref. 2). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the Emergency Core Cooling System (ECCS) pumps. The CL System is designed to perform its function with a single

BASES

APPLICABLE SAFETY ANALYSES (continued)

failure of any active component, assuming the loss of offsite power. This assumes a maximum CL temperature of 95°F occurring simultaneously with design heat loads for the system.

The CL System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two CL trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming that the worst case single active failure occurs coincident with the loss of offsite power.

A CL train is considered OPERABLE when:

a. The safeguards CL pump, aligned to the train, is OPERABLE;

b. The associated header is OPERABLE; and

c. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

A diesel driven safeguards CL pump is considered OPERABLE when:

a. The pump can meet the design flow/pressure requirements in accordance with the Inservice Testing Program;

b. The associated piping, valves, auxiliaries, and instrumentation and controls required to perform the safety related function are OPERABLE; and

c. There is a 7 day stored diesel driven CL pump fuel oil supply available in that train's tanks. The fuel oil supply equivalent to 7 days is 10,825 gallons.

The 121 CL pump starts during low header pressure conditions and it functions as a backup source replacing a diesel driven safeguards

BASES

LCO (continued)

CL pump. In this latter case, additional requirements for OPERABILITY are specified.

121 CL pump is considered OPERABLE when:

a. The pump can meet the design flow/pressure requirements in accordance with the Inservice Testing Program; and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

121 CL pump is considered OPERABLE as the safeguards substitute for 12 diesel driven CL pump when:

a. The pump can meet the design flow/pressure requirements in accordance with the Inservice Testing Program;

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE;

c. MV-32037 or MV-32036 are closed and the associated breaker is locked in the OFF position;

d. MV-32034 and MV-32035 are open and both breakers are locked in the OFF position; and

e. Bus 27 is supplied from Bus 25.

121 CL pump is considered OPERABLE as the safeguards substitute for 22 diesel driven CL pump when:

a. The pump can meet the design flow/pressure requirements in accordance with the Inservice Testing Program;

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE;

BASES

LCO (continued)

c. MV-32034 or MV-32035 are closed and the associated breaker is locked in the OFF position;

d. MV-32036 and MV-32037 are open and both breakers are locked in the OFF position; and

e. Bus 27 is supplied from Bus 26.

Changes in valve positions to align 121 CL pump as the safeguards substitute for either diesel driven CL pump must be under direct administrative control.

With one CL strainer isolated, the containment cooling train on the associated CL header is OPERABLE at CL supply temperatures up to and including 70ºF. When the CL supply temperature is above 70ºF with one CL strainer isolated, the containment cooling train on the associated CL header is not OPERABLE. If Technical Specification (TS) 3.6.5 Condition D has been entered, then the above correlation between CL strainer status, CL supply temperature and containment cooling train OPERBILITY is not applicable. In this case the remaining two containment cooling fan coil units provide adequate heat removal within the TS 3.6.5 Condition D allowed Completion Time.

With both CL strainers isolated or otherwise impaired on a header, the associated CL header is INOPERABLE and TS LCO 3.7.8 Condition B applies. This includes any isolation which could impact the backwash function of both CL strainers.

A header is considered to be OPERABLE when the associated piping, valves, and instrumentation and controls can perform the required safety related functions:

a. Provide flow and cooling for the required safeguards components supplied from the header; and

BASES

LCO (continued)

b. Provide necessary isolation functions required for the header during a safeguards actuation.

Removal of return header piping or components from service does not automatically make the system inoperable. Factors to consider during an OPERABILITY determination are:

a. If the piping or component inoperability results in an individual component being incapable of heat removal, the individual component is to be considered inoperable;

b. If the piping or component inoperability results in required components in a train being incapable of heat removal, the train is to be considered inoperable; and

c. If cooling flow for the required components can be maintained by opening the emergency dump to grade path, by routing to the other unit's discharge header, or overflow from the turbine building standpipes, the train or components are not considered inoperable.

APPLICABILITY

The CL System specification is applicable for single or two unit operation.

In MODES 1, 2, 3, and 4, the CL System is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the CL System and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the CL System are determined by the systems it supports.

BASES

ACTIONS

A.1

If no safeguards CL pumps are OPERABLE for one train, action must be taken to restore one CL safeguards pump to OPERABLE status within 7 days.

Either the diesel driven CL pump for the train may be restored to OPERABLE status, or the 121 CL pump may be aligned to fulfill the safeguards function for the train that has no OPERABLE safeguards CL pump.

The 7 day Completion Time is based on:

a. Low probability of loss of offsite power during the period;

b. The low probability of a DBA occurring during this time period;

c. The safeguards cooling capabilities afforded by the remaining OPERABLE train; and

d. The capability to route water from the non-safeguards pumps, if needed.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for combinations of Conditions A and B to be inoperable during any continuous failure to meet this LCO for these Conditions.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

Required Action A.1 is modified by 3 Notes. Note 1 requires Unit 1 entry into the applicable Conditions and Required Actions of LCO

BASES

ACTIONS

A.1 (continued)

3.8.1, “AC Sources-Operating,” for an emergency diesel generator made inoperable by the CL System. For Unit 1, the diesel generators are major heat loads supplied by the CL System. Thus, inoperability of two safeguards CL pumps will affect at least the heat loads on one CL header, including one Unit 1 diesel generator. Inability to adequately remove the heat from the diesel generator will render it inoperable.

Note 2 requires entry into the applicable Conditions and Required Actions of LCO 3.4.6, “RCS Loops-MODE 4”, for both units for the RHR loops made inoperable by the CL System. If either unit is in MODE 4, inoperability of two safeguards CL pumps may affect all the heat loads on one CL header, including a CC train and subsequently one RHR heat exchanger on each unit. Inability to adequately remove the heat from a RHR heat exchanger will render it inoperable.

Note 3 specifies that the Condition with no safeguard CL pumps OPERABLE for one train may not exist for more than 7 days in any consecutive 30 day period. If such a condition occurs, Condition C must be entered with the specified Required Action taken because the equipment reliability is less than considered acceptable.

B.1, B.2 and B.3

If one CL supply header is inoperable, action must be taken to verify the vertical motor driven CL pump and the opposite train diesel driven CL pump are OPERABLE within 4 hours, and restore the inoperable CL header to OPERABLE status within 72 hours.

Verification of vertical motor driven CL pump OPERABILITY does not require the pump to be aligned and may be performed by administrative means. Verification of the opposite train diesel driven CL pump may be performed by administrative means. Completion of the CL pump surveillance tests is not required.

BASES

ACTIONS

B.1, B.2 and B.3 (continued)

Conditions may occur in the CL System piping, valves, or instrumentation downstream of the supply header (e.g., closed or failed valves, failed piping, or instrumentation in a return header) that can result in the supply header being considered inoperable. In such cases, Condition B and related Required Actions shall apply.

In this Condition, the remaining OPERABLE CL header is adequate to perform the heat removal function. However, the overall redundancy is reduced because only a single CL train remains OPERABLE.

Required Action B.1 ensures that the vertical motor driven 121 CL pump may be used to provide redundancy for the safeguards CL pump on the OPERABLE header. Required Action B.3 assures adequate system reliability is maintained.

The second Completion Time for Required Action B.3 establishes a limit on the maximum time allowed for combinations of Conditions A and B to be inoperable during any continuous failure to meet this LCO for these Conditions.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

Required Actions B.1, B.2, and B.3 are modified by two Notes.

The first Note indicates that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources-Operating," should be entered for Unit 1 since an inoperable CL train results in an inoperable emergency diesel generator.

BASES

ACTIONS

B.1, B.2 and B.3 (continued)

The second Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," should be entered if an inoperable CL train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

The 4 and 72 hour Completion Times are based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period. In addition, the 4 hour Completion Time for Required Actions B.1 and B.2 is within the time period anticipated to verify OPERABILITY of the required CL pump by administrative means.

C.1 and C.2

If at least one safeguards CL pump for a train or a CL supply header cannot be restored to OPERABLE status within the associated Completion Time, the units must be placed in a MODE in which the LCO does not apply. To achieve this status the units must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

This Condition is modified by a note indicating that separate Condition entry is allowed for each stored diesel driven CL pump fuel oil supply. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each

BASES

ACTIONS

D.1 (continued)

inoperable stored diesel driven CL pump fuel oil supply. Complying with the Required Actions for one inoperable stored diesel driven CL pump fuel oil supply may allow for continued operation, and subsequent inoperable stored diesel driven CL pump fuel oil supply is governed by separate Condition entry and application of associated Required Actions.

In this Condition, the 7 day stored diesel driven CL pump fuel oil supply is not available. However, the Condition is restricted to fuel oil supply reductions that maintain at least a 6 day supply. The fuel oil supply equivalent to a 6 day supply is 9,297 gallons. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank(s). A period of 48 hours is considered sufficient to complete restoration of the required supply prior to declaring the diesel driven CL pumps inoperable. This period is acceptable based on the remaining 6 day fuel oil supply, the fact that procedures will be initiated to obtain replenishment, availability of the vertical motor driven CL pump and the low probability of an event during this brief period.

The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for combinations of Conditions A and D to be inoperable during any continuous failure to meet this LCO for these Conditions.

The 9 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and D are entered concurrently. The AND connector between 48 hours and 9 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

BASES

ACTIONS (continued)

E.1

This Condition is modified by a note indicating that separate Condition entry is allowed for each stored diesel driven CL pump fuel oil supply. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable stored diesel driven CL pump fuel oil supply. Complying with the Required Actions for one inoperable stored diesel driven CL pump fuel oil supply may allow for continued operation, and subsequent inoperable stored diesel driven CL pump fuel oil supply is governed by separate Condition entry and application of associated Required Actions

With the stored fuel oil supply not within the limits specified or Required Actions and associated Completion Times of Condition D not met, the diesel driven CL pump may be incapable of performing the intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the CL System components or systems may render those components inoperable, but does not affect the OPERABILITY of the CL System.

This SR verifies the correct alignment for manual, power operated, and automatic valves in the CL System flow path to assure that the proper flow paths exist for CL System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. Control room indication may be used to fulfill this SR. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.8.2

This SR verifies each required diesel driven CL pump can be started and be up to operating speed and assumes load within one minute to provide assurance that equipment would perform as expected in the safety analysis.

Diesel CL pump start will normally be initiated by the manual start switch. Once per calendar year, start should be initiated by use of the low pressure header pressure switch.

The 31 day Frequency is based on the experience that the CL pump usually passes the Surveillance when performed at this Frequency.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.3

This SR provides verification that there is an adequate supply of diesel driven CL pump fuel oil in the storage tanks to support each train's diesel driven CL pump operation for 7 days. The stored diesel fuel oil supply equivalent to a 7 day supply for one train, is 10,825 gallons when calculated in accordance with Regulatory Guide 1.137 (Ref. 3) and ANSI N195-1976 (Ref. 4). The required fuel storage volume is determined using the most limiting energy content of the stored fuel (Ref. 5). Using known correlation of diesel fuel oil absolute specific gravity or API gravity to energy content, the required diesel engine output, and the corresponding fuel consumption rate, the onsite fuel storage volume required for 7 days of operation can be determined. SR 3.8.3.2 requires new fuel to be tested to verify that the absolute specific gravity or API gravity is within the range assumed in the diesel driven CL pump diesel fuel oil consumption calculations. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The diesel driven cooling water pump fuel oil system has two safety related trains. Each train consists of one Design Class I fuel oil storage tank for the diesel driven cooling water pump. The testing and the quality of the fuel oil is controlled by Technical Specification 5.5.11, "Diesel Fuel Oil Testing Program."

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

SR 3.7.8.4

This SR verifies the vertical motor driven CL pump, when required to meet the LCO, is OPERABLE to provide assurance that equipment, when lined up in the safeguards mode, will perform as expected in the safety analysis.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.4 (continued)

For this test, an acceptable level of performance shall be:

a. Pump starts and reaches required developed head; and

b. Control board indications and visual observations indicate that the pump is operating properly for at least 15 minutes.

The 92 day Frequency is based on the Inservice Testing Program requirements (Ref. 6).

Under some plant conditions, the vertical motor driven CL pump is required to operate to provide additional CL flow. When this pump is operated to support plant operations, this test can not be performed and this pump is considered inoperable as a safeguards CL pump.

SR 3.7.8.5

This SR verifies proper automatic operation of the CL System valves on an actual or simulated safety injection actuation signal, including those valves that isolate non-essential equipment from the system. The CL System is a normally operating system that is shared between the two units and cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls.

These tests demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry.

Unit 1 SI actuation circuits for Train A and Train B valves shall be tested during Unit 1 refueling outages. Unit 2 SI actuation circuits for Train A and Train B valves shall be tested during Unit 2 refueling outages.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.5 (continued)

A test is considered satisfactory if control board indication and visual observations indicate that all components have operated satisfactorily and if cooling water flow paths required for accident mitigation have been established.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during an outage of one unit (the other unit may be operating) and the potential for an unplanned transient in the unit affected by the tested components if the Surveillance were performed with that reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.6

The safeguards CL pumps may be actuated by either a safety injection (SI) signal or system low pressure. This SR verifies proper automatic operation of the required diesel driven and vertical motor driven CL pumps on an actual or simulated safety injection actuation signal and verifies proper automatic operation of these pumps on an actual or simulated low pressure actuation signal. The CL is a normally operating system that cannot be fully actuated in a safeguards mode as part of normal testing during normal operation. A test is considered satisfactory if control board indication and visual observations indicate that all components have operated satisfactorily.

The 24 month Frequency is based on the need to perform the SI signal portion of this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.6 (continued)

Operating experience has shown that these components usually pass the Surveillance when performed. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 10.4.
2. USAR, Section 6.
3. Regulatory Guide 1.137, Revision 1.
4. ANSI N195-1976.
5. Calculation ENG-ME-020.
6. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.9 Emergency Cooling Water (CL) Supply

BASES

BACKGROUND

The Emergency CL Supply is designed to provide a supply of screened cooling water (CL) following an earthquake that destroys Dam No. 3, dropping the water level in the normal intake canal supply to the screenhouse. The Emergency CL Supply consists of the Emergency CL Line and the two Safeguards Traveling Screens.

The emergency pump bay, located within the safeguards section of the screen house, houses the safeguards traveling screens, the motor-driven vertical CL pump, and the diesel-driven vertical CL pumps. Two normally open sluice gates, one from each unit's circulating water (CW) pump bay, provide water to the vertical CL pumps. Sluice gates may be used to isolate the emergency bay from the CW pump bays.

Under design basis seismic event conditions, water will be supplied to the emergency bay through an Emergency CL. The 36 inch pipe, buried in the approach canal and Circulating Water Intake Canal bottom, directs water from the deepest part of the river to the emergency bay. The intake end of the pipe is covered with a screen to minimize the amount of trash drawn into the pipe. The Emergency CL is designed to provide adequate flow at the lowest possible water elevation resulting from loss of Dam No. 3. The pipe is buried approximately 40 feet below the Circulating Water Intake Canal water level.

Two safeguards traveling screens are designed to remove debris from the cooling water entering the emergency pump bay through the Emergency CL Line. Trash trays attached to the screens aid in carrying the trash to a trash trough. The screens have two speeds. The screens are backwashed with water supplied from the CL pump discharge.

BASES

BACKGROUND (continued)	Additional information on the design and operation of the Safeguards Traveling Screens and the Emergency CL Line can be found in Reference 1.
APPLICABLE SAFETY ANALYSES	The Design Basis Earthquake provides the basis for the Emergency CL Supply. This safety analysis assumes that Dam No. 3 is destroyed by the seismic event, such that supply through the Emergency CL Line is required. Under these conditions, trash removal by the safeguards traveling screens is required. The Emergency CL Supply satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This specification applies to single or dual unit operation. The Emergency CL Supply is a passive gravity fed supply to the safeguards CL pumps intended only for the case of a seismic event that destroys Dam No. 3 resulting in low level in the intake canal. In this low probability event, the safeguards traveling screens would be required to remove debris from the water supply to the pumps. Both safeguards traveling screens are required to be OPERABLE. A safeguards traveling screen is considered OPERABLE when: a. The valve, instrumentation and controls required to provide the screen backwash function are OPERABLE; and b. The safeguards traveling screen can turn.

BASES

LCO (continued)

Safeguards traveling screen OPERABILITY is not required for OPERABILITY of the safeguards CL pumps (LCO 3.7.8).

The Emergency CL Line is OPERABLE when a flow path through the pipe exists.

APPLICABILITY

With either unit in MODES 1, 2, 3, and 4, the Safeguards Traveling Screens and Emergency CL Line are required to support the OPERABILITY of the equipment serviced by the CL System during the design basis condition and required to be OPERABLE in these MODES.

With both units in MODE 5 or 6, the OPERABILITY requirements of the Emergency CL Supply are determined by the systems it supports. The design basis does not include shutdown conditions.

ACTIONS

A.1 and A.2

If one safeguards traveling screen is inoperable, action must be taken to verify an emergency bay sluice gate is open within 4 hours, and restore that safeguards traveling screen to OPERABLE status within 90 days.

BASES

ACTIONS

A.1 and A.2 (continued)

In this Condition, the remaining OPERABLE safeguards traveling screen or open emergency bay sluice gate is adequate to provide the CL supply to any of the three vertical CL pumps during any design basis condition.

Required Action A.1 is modified by a Note which states the action is not required during testing periods of less than or equal to 24 hours. The 24 hours allows testing of the emergency cooling water line which may require the sluice gates to be closed. This is acceptable based on plant experience to perform the required testing during this time period and the OPERABILITY of the other emergency traveling screen.

The 4 hour Completion Time is based on the redundant capability afforded by the OPERABLE safeguards traveling screen.

The 90 day Completion Time is based on:

a. The redundant capability afforded by the remaining OPERABLE safeguards traveling screen;

b. The low risk impact of an inoperable safeguards traveling screen; and

c. The low probability of a high magnitude earthquake that could destroy Dam No. 3 during this time interval.

BASES

ACTIONS (continued)

B.1 and B.2

If both safeguards traveling screens are inoperable, action must be taken to verify one emergency bay sluice gate is open within 1 hour, and restore one safeguards traveling screen to OPERABLE status within 7 days.

In this Condition, the open emergency bay sluice gate is adequate to perform the CL supply function except in those cases where use of the Emergency CL Line is needed. As a result, overall reliability is reduced.

The 7 day Completion Time is based on the low probability of a design basis earthquake occurring during this time interval.

C.1 and C.2

If the Emergency CL Line is inoperable, action must be taken to verify one emergency bay sluice gate is open within 1 hour, and restore the Emergency CL Line to OPERABLE status within 7 days.

The 1 hour and 7 day Completion Times are reasonable based on the low probability of a design basis earthquake occurring during the 7 days that the Emergency CL Line is inoperable, the availability through the normal operating path and associated traveling screens, and the time required to reasonably complete the Required Actions.

BASES

ACTIONS (continued)

D.1 and D.2

If the Emergency CL Line or Safeguards Traveling Screen(s) cannot be restored to OPERABLE status within the associated Completion Time, the units must be placed in a MODE in which the LCO does not apply. To achieve this status, the units must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies that the safeguards traveling screens can adequately filter (screen) water and that screens can backwash as needed.

This SR verifies that:

a. The backwash supply valve will open;

b. Backwash water pressure is sufficient; and

c. The safeguards traveling screens can turn.

The 92 day Frequency is based on operating experience that demonstrates this interval is sufficient to ensure screen and support equipment reliability.

REFERENCES

1. USAR, Section 10.4.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Special Ventilation System (CRSVS)

BASES

BACKGROUND

The CRSVS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals or smoke.

The CRSVS consists of two independent, redundant trains that recirculate and filter the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each CRSVS train consists of an air handling unit, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a cleanup fan.

Ductwork, valves or dampers, and instrumentation also form part of the system.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room and may encompass non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CRSVS is an emergency system, parts of which may also operate during normal unit operation.

BASES

BACKGROUND (continued)

Upon receipt of the actuating signal(s), normal air supply to the CRE is isolated, and the stream of ventilation air is recirculated through the system filter trains. The prefilters remove any large particles in the air, and any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers.

Actuation of the CRSVS is initiated by:

a. High radiation in the control room ventilation duct; or

b. Safety injection signal.

Actuation of the system closes the unfiltered outside air intake and unfiltered exhaust dampers, and aligns the system for recirculation of the air within the CRE through the redundant trains of HEPA and the charcoal filters. The operating condition initiates filtered ventilation of the air supply to the CRE.

The CRSVS operation is discussed in the USAR (Ref. 1).

Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. The CRSVS is designed in accordance with Seismic Category I requirements.

The CRSVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding 5 rem TEDE.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The CRSVS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CRSVS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the most limiting design basis accident fission product release presented in the USAR (Ref. 2). The CRSVS function also plays a significant role in protecting CRE personnel during a fuel handling accident in the spent fuel pool enclosure or the containment (Ref. 2).

The worst case single active failure of a component of the CRSVS does not impair the ability of the system to perform its design function.

The CRSVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO applies to single or dual unit operation since there is a single CRSVS for both units.

Two independent and redundant CRSVS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body or 5 rem TEDE, as applicable, (Ref. 3) to the CRE occupants during the worst 4 week exposure following a postulated accident.

Each CRSVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CRSVS train is OPERABLE when the associated:

BASES

LCO (continued)

a. Cleanup fan is OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions;

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained;

d. Instrumentation, including associated radiation monitor for starting the cleanup fan, is OPERABLE, or the system is aligned to perform its safety function and is operating; and

e. Air Handling Unit is OPERABLE.

In order for the CRSVS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

Opening a door for personnel ingress or egress does not make the CRE boundary inoperable. Blocking a door open (e.g., for maintenance) without a person present to close the door requires entry into an ACTION.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. The Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated

BASES

LCO (continued)	individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.
APPLICABILITY	In MODES 1, 2, 3, and 4 for either unit, CRSVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA. In addition, during movement of irradiated fuel assemblies, the CRSVS must be OPERABLE to cope with the release from a fuel handling accident.
ACTIONS	<u>A.1</u> When one CRSVS train is inoperable, for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRSVS train is adequate to perform the CRE occupant protection function. However, the overall redundancy is reduced because only a single CRSVS train remains OPERABLE. The 7 day Completion Time is based on the low probability of a DBA or fuel handling accident occurring during this time period, and ability of the remaining train to provide the required capability.

ACTIONS (continued)

B.1, B.2, and B.3

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem whole body or its equivalent to any part of the body or 5 rem TEDE, as applicable), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e. actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

ACTIONS (continued)

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable CRSVS train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, both units must be placed in a MODE that minimizes accident risk. To achieve this status, the units must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

If the inoperable CRSVS train cannot be restored to OPERABLE status within the required Completion Time, Required Action D.1 must be taken to immediately place the OPERABLE CRSVS train in operation. This is a reasonable action, based on engineering judgment, to assure the CRE air is filtered in the event of an accident.

An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. Required Action D.2 places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

BASES

ACTIONS (continued)

E.1

If two CRSVS trains are inoperable or with one or more CRSVS trains inoperable due to an inoperable CRE boundary during movement of irradiated fuel assemblies, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

F.1

If both CRSVS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than inoperable CRE boundary (i.e., Condition B) the CRSVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately for both units.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month provides an adequate check of this system. Each train must be operated for $\geq$15 minutes to demonstrate the system functions. The 31 day Frequency is based on the reliability of the equipment and the two train redundancy.

SR 3.7.10.2

This SR verifies that the required CRSVS filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.3

The CRSVS may be actuated by either a safety injection signal or a high radiation signal. This SR verifies that each CRSVS train starts and operates on an actual or simulated safety injection actuation signal and verifies each CRSVS train starts and operates on an actual or simulated high radiation signal. The Frequency of 24 months allows performance when a unit is shutdown.

SR 3.7.10.4

This SR verifies proper functioning of the CRSVS in the Emergency Mode (Ref. 1). During operation, in the Emergency Mode, the CRSVS train is designed to provide 4000 ± 10% cfm through the PAC filter unit.

The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with industry component reliability experience.

SR 3.7.10.5

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air in-leakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem whole body or its equivalent to any part of the body or 5 rem TEDE, as applicable, and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air in-leakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air in-leakage is greater than the assumed flow rate, Condition B must be entered. Required

SURVEILLANCE REQUIREMENTS

SR 3.7.10.5 (continued)

Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 4) which endorses, with exceptions, NEI 99-03, Section 8.4 and BASES Appendix F (Ref. 5). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 6). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope in-leakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. USAR, Section 10.3.

2. USAR, Chapter 14.

3. 10 CFR 50 Appendix A, GDC Criterion 19.

4. Regulatory Guide 1.196, “Control Room Habitability at Light-Water Nuclear Power Reactors,” dated January 2007.

5. NEI 99-03, “Control Room Habitability Assessment,” June 2001.

6. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability.” (ADAMS Accession No. ML040300694).

B 3.7 PLANT SYSTEMS

B 3.7.11 Safeguards Chilled Water System (SCWS)

BASES

BACKGROUND

The SCWS, a shared system between the two units, circulates chilled water to provide ambient air cooling to essential areas, including the control room, Unit 1 safeguards 4160 VAC and 480 VAC safeguards bus rooms, residual heat removal (RHR) pump pits, relay room, and the event monitoring equipment room. The system functions during normal plant operations and accident conditions. The system function is to remove heat generated by safety related equipment and accident conditions.

The SCWS consists of two separate, but normally cross-connected, closed 100% capacity loops. Each loop consists of a header with water chiller, expansion tank, chilled water pump, unit coolers, piping, valves, instrumentation, and controls.

A safety injection (SI) signal closes the control room chiller outlet cross-connect air operated control valves, splitting the two headers so that each header is then supplied by the associated chilled water pump and chiller.

The SCWS operation is discussed in the USAR (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the SCWS is to remove heat produced by equipment located in the various rooms during worst case heatup scenarios. The heat removal rates exceed the design basis heat generation rates in the control room, Unit 1 safeguards 4kV and 480 VAC rooms, relay room, computer room, RHR pits, and event monitoring equipment room.

In event of a single failure affecting one loop of safeguards chilled water, the alternate loop is able to meet required heat load demands.

The SCWS satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

BASES (continued)

LCO

The SCWS is a shared system between the two units.

Two 100% capacity loops of the SCWS are required to be OPERABLE to ensure that at least one is available, assuming a single failure.

Even if both loops should fail, operator actions are available in procedures to provide sufficient cooling to these rooms. The RHR pumps, 480V buses and 4kV buses can perform their functions without an immediate need for equipment heat removal and their long term OPERABILITY is handled by procedures as discussed in Reference 1. The control room and relay room can provide their functions for a shorter time period before replacement heat removal is required and long term operability is handled by procedures.

The SCWS is considered to be OPERABLE when the individual components (chiller and chilled water pump) necessary to maintain the supplied components and rooms are OPERABLE in both loops. A loop is OPERABLE when:

a. Chiller is OPERABLE;

b. Chilled water pump is OPERABLE; and

c. Loop separation function, required during an accident, is OPERABLE.

Isolation of components or systems from SCWS may render those components or systems inoperable but does not affect the OPERABILITY of the SCWS.

APPLICABILITY

In MODES 1, 2, 3, and 4 and during movement of irradiated fuel assemblies, the SCWS must be OPERABLE to ensure that the room temperatures will not exceed equipment operational requirements in the essential areas this system serves following an accident.

BASES

APPLICABILITY (continued)	In MODES 5 and 6, the OPERABILITY requirements of the SCWS are determined by the systems it supports.

ACTIONS

A.1

With one SCWS loop inoperable, action must be taken to restore OPERABLE status within 30 days.

In this Condition, the remaining OPERABLE SCWS loop is adequate to provide cooling. However, the overall reliability is reduced because a single failure in the OPERABLE SCWS loop could result in loss of SCWS function.

The 30 day Completion Time is based on the low probability of an event requiring SCWS loop separation, the consideration that the remaining loop can provide the required protection, and that alternate safety or nonsafety related cooling means are available.

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable SCWS loop cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes the risk.

To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

C.1 and C.2

During movement of irradiated fuel, if the inoperable SCWS loop cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE SCWS loop must be placed in operation immediately. This action ensures that the required cooling function is provided.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. Required Action C.2 places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

D.1

During movement of irradiated fuel assemblies, with two SCWS loops inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the control room.

This Action minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

If both SCWS loops are inoperable in MODE 1, 2, 3, or 4, the SCWS may not be capable of performing its intended function. Therefore, LCO 3.0.3 must be entered immediately.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that each SCWS loop actuates on an actual or simulated safety injection actuation signal.

The 24 month Frequency on a STAGGERED TEST BASIS is appropriate since significant degradation of the SCWS is slow and is not expected over this time period.

SR 3.7.11.2

This SR verifies that necessary components in each SCWS loop operate as required.

The Frequency required by the Inservice Testing Program (Ref. 2) is appropriate since degradation of the SCWS could be detected in a timely manner for the components specified based on the known reliability of the components and the loop redundancy.

REFERENCES

1. USAR, Section 10.4.

2. Inservice Testing Program.

B 3.7 PLANT SYSTEMS

B 3.7.12 Auxiliary Building Special Ventilation System (ABSVS)

BASES

BACKGROUND

The ABSVS is a standby ventilation system, common to the two units, that is designed to collect and filter air from the Auxiliary Building Special Ventilation (ABSV) boundary following a loss of coolant accident (LOCA). The ABSV boundary contains those areas within the auxiliary building which have the potential for collecting significant containment leakage that could bypass the shield building and leakage from systems which could recirculate primary coolant during LOCA mitigation.

Whereas the ABSVS function during plant operating modes is to contain the radioactivity release within the ABSV boundary and process it accordingly, the ABSVS function for the fuel handling accident (in containment or spent fuel pool) is to maintain a ABSV boundary that prevents the radioactivity release that occurs outside the ABSV boundary from entering into the Auxiliary Building Special Ventilation Zone (ABSVZ). This refueling function is therefore unique and does not require further processing of the released radioactivity (because the radioactivity is prevented from entering the ABSVZ).

The ABSVS consists of two independent and redundant trains. Each train consists of a heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan.

Ductwork, dampers, and instrumentation also form part of the system. The system initiates filtered ventilation of the ABSV boundary following receipt of a safety injection (SI) signal, high radiation signal or manual initiation. The radiation signal is not credited in the USAR for accident mitigation.

BACKGROUND (continued)	The exhaust from the main condenser air ejector is directed to the ABSVS for filtering prior to exhausting from the plant via the shield building stack to mitigate steam generator tube leakage. When the ABSVS actuates, the normal nonsafeguards supply and exhaust dampers close automatically, and the Auxiliary Building Normal Ventilation System supply and exhaust fans trip. The prefilters remove any large particles in the air, and with the heaters, reduce the level of entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers. The heaters are designed to dry incoming air at 100% saturation by increasing the temperature of the air entering the charcoal bed. The air is then dry enough to support the charcoal adsorber iodine removal efficiency requirements. The ABSVS would typically only be used for post accident atmospheric cleanup functions. The ABSVS and ABSV boundary are discussed in the USAR (References 1, 2 and 3).
APPLICABLE SAFETY ANALYSES	The design basis of the ABSVS is established by the large break LOCA. The potential leakage paths from the containment to the auxiliary building are discussed in Reference 1. The system evaluation assumes a passive failure of the ECCS outside containment, such as an RHR pump seal failure, during the recirculation mode (Ref. 4). In such a case, the system limits radioactive release to within the 10 CFR 50.67 (Ref. 5) limits. The analysis of the effects and consequences of a large break LOCA is presented in References 3 and 4. The ABSVS also actuates following a small break LOCA, in those cases where the ECCS goes into the recirculation mode of long term cooling, to clean up releases of smaller leaks, such as from valve stem packing. A less-limiting function of the ABSVS is to prevent the radiological release of the fuel handling accident (FHA) from entering the ABSVZ. Whether the accident initiates in the SFP or in the containment, the radiological analyses of the FHA assume the

BASES

APPLICABLE SAFETY ANALYSES (continued)

release point is the Common Area of the Auxiliary Building (CAAB), which is considered the limiting release point for Control Room dose evaluation. The ABSVZ boundary prevents the intrusion of radioactivity into the ABSVZ where it may be exhausted out the ABNVS Exhaust Stack(s), which may be closer to the respective Control Room intake than the assumed release point. These radiological analyses do not take any credit for ABSVS fan operation or filtering; the only credited function is isolation. Noting however that the ABSV boundary operability allows up to 10 square feet of openings through which the FHA plume could be assumed to pass, credit is taken for ABSVS actuation on the High Radiation signal whereupon the plume is filtered and discharged from a location that is less limiting for the Control Room dose than that assumed in the analysis (i.e., the CAAB).

The ABSVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the ABSVS are required to be OPERABLE to ensure that at least one is available, assuming that a single failure disables the other train.

This OPERABILITY requirement ensures that the atmospheric releases, in the event of a Design Basis Accident (DBA) in containment, from ECCS pump leakage and containment leakage which bypasses the shield building would not result in doses exceeding 10 CFR 100 limits (Ref. 5).

In order for the ABSVS to be OPERABLE, the Turbine Building roof exhauster fans must be capable of being de-energized within 30 minutes following a loss of coolant accident.

BASES

LCO (continued)

An ABSVS train is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorbers are capable of passing their design flow and performing their filtration functions;

c. Heater, ductwork, and dampers are OPERABLE and air circulation can be maintained; and

d. Instrumentation and controls are OPERABLE.

The ABSV boundary is OPERABLE if both of the following conditions can be met:

a. Openings in the ABSV boundary are under direct administrative control and can be reduced to less than 10 square feet within 20 minutes following an accident; and

b. Dampers and actuation circuits that isolate the Auxiliary Building Normal Ventilation System following an accident are OPERABLE or can be manually isolated within 20 minutes following an accident.

The LCO is modified by a Note allowing the ABSV boundary to be opened under administrative controls. As discussed above, openings must be closed to less than 10 square feet within 20 minutes following an accident.

APPLICABILITY

In MODES 1, 2, 3, and 4 for either unit, the ABSVS is required to be OPERABLE.

In addition, during movement of irradiated fuel assemblies, the ABSV boundary must be OPERABLE to prevent releases from a fuel handling accident from entering the ABSV zone.

BASES (continued)

ACTIONS

A.1

With one ABSVS train inoperable, action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the ABSVS function.

The 7 day Completion Time is appropriate because the ABSVS risk contribution is substantially less than that for the ECCS (72 hour Completion Time). The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

Concurrent failure of two ABSVS trains would result in the loss of functional capability; therefore, LCO 3.0.3 must be entered immediately.

B.1

In MODE 1, 2, 3, or 4, with both ABSVS trains inoperable due to an inoperable ABSV boundary, action must be taken to restore OPERABLE status within 24 hours.

The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the availability of the ABSVS to provide a filtered release (albeit with potential for some unfiltered leakage).

If the ABSV boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply.

C.1 and C.2

In MODE 1, 2, 3, or 4, if an ABSVS train cannot be restored to OPERABLE status or the ABSV boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply.

BASES

ACTIONS

C.1 and C.2 (continued)

To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

With both ABSVS trains inoperable due to an inoperable ABSV boundary or if the inoperable ABSVS train cannot be restored to OPERABLE status within the required Completion Time during movement of irradiated fuel assemblies, action must be taken immediately to suspend activities that could result in a release of radioactivity. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR verifies that each ABSVS train can be manually started and the associated filter heater energizes.

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train once a month provides an adequate check on this system. Each ABSVS train must be operated ≥ 15 minutes per month with the heaters energized. The 31 day Frequency is based on the known reliability of equipment and the two train redundancy available.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.2

This SR verifies that the required ABSVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorbers efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations).

Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.12.3

This SR verifies proper functioning of the ABSVS by verifying the integrity of the ABSV boundary and the ability of the ABSVS to maintain a negative pressure with respect to potentially uncontaminated adjacent areas.

During the post accident mode of operation, the ABSVS is designed to maintain a slight negative pressure within the ABSV boundary with respect to the containment and shield building.

Each ABSVS train is started from the control room and the following are verified:

a. Associated Auxiliary Building Normal Ventilation System fans trip and dampers close; and

b. A measurable negative pressure is drawn within the ABSV boundary within 20 minutes after initiation, with a 10 square foot opening within the ABSV boundary.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.12.3 (continued)

The 92 day Frequency is based on the known reliability of equipment and the two train redundancy available.

SR 3.7.12.4

The ABSVS initiates on a safety injection signal, high radiation signal or manual actuation. This SR verifies that each ABSVS train starts and operates on an actual or simulated safety injection actuation signal or on manual initiation.

The 24 month Frequency is consistent with industry reliability experience for similar equipment. The 24 month Frequency is acceptable since this system usually passes the Surveillance when performed.

REFERENCES

1. USAR, Appendix G.
2. USAR, Section 10.3.
3. USAR, Section 14.
4. USAR, Section 6.7.
5. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.13 Not Used

B 3.7 PLANT SYSTEMS

B 3.7.14 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment during normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 150 gpd tube leak (LCO 3.4.14, “RCS Operational LEAKAGE”) of primary coolant at the limit of 0.5 μCi/gm (LCO 3.4.17, “RCS Specific Activity”). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours).

Limiting secondary specific activity also reduces site and exclusion area boundary (EAB) exposures in the event of a steam generator tube rupture (Ref. 1).

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB) outside of containment, as discussed in the USAR (Ref. 1) assume the initial secondary coolant specific activity to have a radioactive isotope

BASES

APPLICABLE SAFETY ANALYSES (continued)

concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of a MSLB do not exceed a small fraction of the unit EAB limits of 10 CFR 50.67.

With the loss of offsite power, the remaining steam generator is available for core decay heat dissipation by venting steam to the atmosphere through the main steam safety valves (MSSVs) and steam generator power operated relief valve (SG PORV). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the SG PORV and TDAFW Pump Steam Exhaust during the event. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

With the specified activity limit, the resultant 2 hour dose to a person at the EAB would be a very small fraction of Reference 3 requirements.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (Ref. 3).

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours.

BASES

ACTIONS

A.1 and A.2 (continued)

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE.

The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. USAR, Section 14.5.

2. Deleted.

3. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the spent fuel storage pool design and a description of the Spent Fuel Pool Cooling and Cleanup System is given in the USAR (Ref. 1). The assumptions of the fuel handling accident are given in Reference 2.

APPLICABLE SAFETY ANALYSES

The minimum water level in the spent fuel storage pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 3). The resultant 2 hour dose per person at the exclusion area boundary is a small fraction of the 10 CFR 50.67 limits.

According to Reference 3, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 3 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be < 23 ft of water above the top of the fuel bundle and the surface, indicated by the width of the bundle. To offset this small nonconservatism, the analysis assumes that all fuel rods fail, although analysis shows that only the first few

BASES

APPLICABLE SAFETY ANALYSES (continued)	rows fail from a hypothetical maximum drop. The Fuel Handling Accident is discussed in Reference 2. The spent fuel storage pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The spent fuel storage pool water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for spent fuel movement within the spent fuel storage pool.
APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the spent fuel storage pool, since the potential for a release of fission products exists.
ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the spent fuel storage pool is immediately suspended. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel

BASES

ACTIONS	A.1 (continued) assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.
SURVEILLANCE REQUIREMENTS	SR 3.7.15.1 This SR verifies sufficient spent fuel storage pool water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool must be checked periodically. The 7 day Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience. During refueling operations, the level in the spent fuel storage pool is in equilibrium with the refueling cavity, and the level in the refueling cavity is checked daily in accordance with SR 3.9.2.1.
REFERENCES	1. USAR, Section 10.2. 2. USAR, Section 14.5. 3. Regulatory Guide 1.183, dated July 2000.

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

The spent fuel storage pool is a two compartment pool as described in Reference 1. These 2 compartments are referred to as Pool 1 and Pool 2. Pool 1 has up to 462 storage positions. Pool 2 has up to 1120 storage positions.

Either pool is designed to accommodate fuel of various initial enrichments (up to 5 weight percent (w/o)) which satisfy the storage requirements described in TS Section 3.7.17, “Spent Fuel Pool Storage,” and TS Section 4.3, “Fuel Storage”.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 1.00 be evaluated in the absence of soluble boron. The double contingency principle discussed in Reference 2 and the April 1978 NRC letter (Ref. 3) allows credit for additional soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. Safe operation of the spent fuel pool may therefore be achieved by controlling the location of each assembly in accordance with LCO 3.7.17, “Spent Fuel Pool Storage” and by maintaining boron concentration in accordance with this LCO.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The spent fuel pool criticality analysis (Ref. 4) addresses all the fuel types currently stored in the spent fuel pool and in use in in the reactor. The fuel types considered in the analysis include the Westinghouse Standard (STD), OFA, and Vantage Plus designs, (both 0.400" and 0.422" O.D. designs) and the Exxon fuel assembly types in storage in the spent fuel pool.

Accident conditions which could increase the k_{eff} were evaluated including:

a. A new fuel assembly drop on the top of the racks;
b. A new fuel assembly misloaded between rack modules;
c. A new fuel assembly misloaded into an incorrect storage rack location;
d. Intramodule water gap reduction due to a seismic event; and
e. Spent fuel pool temperature greater than 150 ºF.

For an occurrence of these postulated accident conditions, the double contingency principle of Reference 2 can be applied. This states that one is not required to assume two unlikely, independent, concurrent events to ensure protection against a criticality accident. Thus, for these postulated accident conditions, the presence of additional soluble boron in the spent fuel pool water (above the 359 ppm required to maintain k_{eff} less than 0.95 under normal conditions) can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event.

Calculations were performed (Ref. 4) to determine the amount of soluble boron required to offset the highest reactivity increase caused by these postulated accidents and to maintain k_{eff} less than or equal to 0.95. It was found that a spent fuel pool boron concentration of 910 ppm (assuming a conservatively low boron-10 atom percent of 19.4) was adequate to mitigate these postulated criticality related accidents and to maintain k_{eff} less than or equal to 0.95. This specification ensures the spent fuel pool contains

BASES

APPLICABLE SAFETY ANALYSES (continued)

adequate dissolved boron to compensate for the increased reactivity caused by these accidents.

A spent fuel pool boron dilution analysis was performed which confirmed that sufficient time is available to detect and mitigate a dilution of the spent fuel pool before the 0.95 k_{eff} design basis is exceeded. The spent fuel pool boron dilution analysis concluded that an unplanned or inadvertent event which could result in the dilution of the spent fuel pool boron concentration from 1800 ppm to 750 ppm is not a credible event.

The current spent fuel rack criticality analysis (Ref. 4) only requires a boron concentration of 359 ppm (assuming a conservatively low boron-10 atom percent of 19.4) to ensure that the spent fuel rack k_{eff} will be less than or equal to 0.95 for the allowable storage configuration, excluding accidents. Therefore the spent fuel pool boron dilution analysis which assumes 750 ppm as the endpoint of the analysis is conservative with respect to the endpoint of 359 ppm since a larger volume of water would be required, which would take more time to dilute the spent fuel pool to 359 ppm.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The fuel storage pool boron concentration is required to be ≥ 1800 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 4. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the fuel storage pool.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool.

ACTIONS

A.1 and A.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the spent fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. This does not preclude movement of a fuel assembly to a safe position.

If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies that the concentration of boron in the spent fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

REFERENCES

1. USAR, Section 10.2.
2. ANSI/ANS-8.1-1983.
3. Nuclear Regulatory Commission, Letter to All Power Reactor Licensees from B. k. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications", April 14, 1978.
4. "Prairie Island Units 1 and 2 Spent Fuel Pool Criticality Analysis", WCAP-17400-NP, Revision 0, Westinghouse Electric Company, July 2011.

B 3.7 PLANT SYSTEMS

B 3.7.17 Spent Fuel Pool Storage

BASES

BACKGROUND

The spent fuel storage pool is a two compartment pool as described in the USAR (Ref. 1). These 2 compartments are referred to as Pool 1 and Pool 2.

Criticality considerations provide the primary basis for storage limitations.

Pool 1 may contain up to 462 storage positions, except when the pool is used for cask laydown. In the latter case, only 266 storage positions are available since 4 storage racks must be removed to accommodate the storage cask. Pool 2 has up to 1120 storage positions.

Pools 1 and 2 are designed to accommodate fuel of various initial enrichments (up to 5 weight percent (w/o)), which satisfy the storage requirements described in Specification 3.7.17 and Specification 4.3, "Fuel Storage".

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 1.00 be evaluated in the absence of soluble boron. The double contingency principle discussed in Reference 2 and the April 1978 NRC letter (Ref. 3) allows credit for additional soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. To mitigate postulated criticality related accidents, boron is dissolved in the pool water. Safe operation of the spent fuel pool may therefore be achieved by controlling the location of each assembly in accordance with the accompanying LCO and maintaining boron concentration in accordance with LCO 3.7.16.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The hypothetical criticality accidents can only take place during or as a result of the movement of an assembly (Ref. 4 and 5). For these accident occurrences, the presence of soluble boron in the spent fuel storage pool (controlled by LCO 3.7.16, "Fuel Storage Pool Boron Concentration") prevents criticality. By closely controlling the movement of each assembly and by verifying the appropriate checkerboarding after each fuel handling campaign, the time period for potential accidents may be limited to a small fraction of the total operating time. During the remaining time period with no potential for criticality accidents, the operation may be under the auspices of the accompanying LCO.

The spent fuel storage racks have been analyzed in accordance with the methodology contained in Reference 4. That methodology ensures that the spent fuel rack multiplication factor, k_{eff}, is less than the values required by 10 CFR 50.68(b). The codes, methods and techniques contained in the methodology are used to satisfy these criteria for k_{eff}. The resulting Prairie Island spent fuel rack criticality analysis allows for the storage of fuel assemblies with enrichments up to a maximum of 5.0 (nominal 4.95% $\pm$ 0.05%) weight percent U-235 while maintaining $k_{eff} \leq 1.0$ (including uncertainties) if flooded with unborated water and $k_{eff} \leq 0.95$ (including uncertainties) with credit for soluble boron. The analysis determined that a minimum soluble boron concentration of 359 ppm (at a conservatively low boron-10 atom percent of 19.4) will ensure any loaded configuration k_{eff} will be ≤ 0.95. In addition, the analysis differentiated a fuel assembly operated during Operating Cycle 1 – 4 from an assembly operated after Cycle 4 in determining the assembly's reactivity. Credit is taken for the radioactive decay time of the spent fuel. No credit is given for any gadolinium burnable poison in the fuel.

The criticality analysis (Ref. 4) specifically analyzed each of the following storage configurations to ensure that the spent fuel pool will remain subcritical when fuel is placed in accordance with Specification 4.3.1.1.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In each array described below, the fuel assemblies are first categorized by their relative reactivity by using Tables 4.3. through 4.3.1-3. The purpose of any array is to combine the use of low-reactivity fuel and/or empty cells to offset higher-reactivity fuel. Parameters that define a fuel category include initial enrichment, burnup, decay time, and the fuel assembly's operating cycles. Each of the approved arrays and the array interface requirements are described below:

Array A represents a 2x2 "all-cell" configuration of low-reactivity (Category 6 fuel) in every cell. Category 6 assemblies are those that satisfy the burnup requirement (for Category 6) defined by the polynomial equations provided in Tables 4.3.1-2 or 4.3.1-3.

Array B represents a 2x2 cell configuration of high-reactivity (Category 3 fuel) in three cells, offset by the empty cell in the fourth location. This array was provided to accommodate the temporary placement of high-reactivity (e.g., once-burned) fuel during a refueling or maintenance outage.

Array C represents a 2x2 cell configuration of new fresh fuel (Category 1 fuel), offset by the empty cells in the checkerboard pattern to reduce the overall reactivity of the configuration. This array was provided to accommodate the temporary pre-staging of fresh fuel for a refueling outage or to accommodate low-burnup fuel that might be discharged prior to a full cycle of depletion (maintenance outage or fuel failure).

Array D represents a 2x2 cell configuration of one fresh fuel assembly plus two medium reactivity fuel (Category 5 fuel) assemblies offset by one empty cell face-adjacent to the fresh assembly. This array was provided to accommodate more efficient storage for a fresh (or low-burnup) assembly and other medium-burnup fuel that might be required for a mid-cycle maintenance outage requiring core offload. For any given

APPLICABLE SAFETY ANALYSES (continued)

amount of low-burnup (Category 1) fuel that an outage may require, this configuration would require approximately half as many empty cells as would otherwise be required if Array C were used.

Array E represents a 2x2 cell configuration of two low-burnup fuel assemblies (Category 2) in a checkerboard pattern with one medium burnup (Category 4) assembly plus an empty cell in a checkerboard pattern to offset the reactivity. This array provides efficient storage of once-burned and twice-burned fuel that would be discharged for a refueling outage.

Array F represents a 2x2 cell configuration that is specifically provided to accommodate the fuel rods from 36 fuel assemblies that were consolidated into 18 Consolidated Rod Storage Canisters (CRSCs) and loaded in a checkerboard pattern with the remnants of the 36 fuel assemblies. This array was specifically analyzed with significant stainless steel materials in the cells face-adjacent to the CRSCs to address the remnants as described in the USAR Section 10.2.1.5. Otherwise, as described in TS Figure 4.3.1-1 Note 5**,** cells designated to be empty in the other arrays must be empty.

Array G represents a 3x3 cell configuration very similar to Array A "all-cell", but requiring a lower burnup value for the fuel (Array A requires Category 6 fuel whereas Array F only requires Category 5 fuel). This relaxation is offset by the requirement to insert and maintain a Rod Control Cluster Assembly (RCCA) in the center location to reduce the overall reactivity of the modified "all-cell" configuration. This array was provided for spent (thrice-burned) fuel that may not have accumulated enough burnup to qualify as Category 6 fuel. This array also puts into use RCCAs that would otherwise just take up space in the spent fuel pool.

Rack interface requirements: The Technical Specifications do not provide any unique rules for the interface between rack

BASES

APPLICABLE SAFETY ANALYSES (continued)

modules because all the racks in the SFP have identical fuel cell design and the actual physical gap between rack modules is ignored in the analysis (i.e., there is no credit taken for the gaps between rack modules).

Array interface requirements: Technical Specifications provide only one special interface requirement between different arrays. This specific interface is described in Figure 4.3.1-1 Note 7 (Array F shall interface only with Array A) and was specifically analyzed. Otherwise, the Technical Specifications do not provide any unique rules for the interface between arrays. Rather, the Technical Specifications require that all fuel in the spent fuel pool satisfy one of the required arrays, even in transitions between two major arrays.

Specification 3.7.17 and Specification 4.3 ensure that fuel is stored in the spent fuel racks in accordance with the storage configurations assumed in the spent fuel rack criticality analysis (Ref. 4).

The spent fuel pool criticality analysis addresses all the fuel types currently stored in the spent fuel pool and in use in the reactor. The fuel types considered in the analysis include the Westinghouse Standard (STD), OFA, and Vantage Plus designs (both 0.400" and 0.422" O.D. designs), and the Exxon fuel assembly types in storage in the spent fuel pool.

Accident conditions which could increase the k_{eff} were evaluated including:

a. A new fuel assembly drop on the top of the racks;

b. A new fuel assembly misloaded between rack modules;

c. A new fuel assembly misloaded into an incorrect storage rack location;

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. Intramodule water gap reduction due to a seismic event; and

e. Spent fuel pool temperature greater than 150°F.

For an occurrence of these postulated accident conditions, the double contingency principle of Reference 2 can be applied. This states that one is not required to assume two unlikely, independent, concurrent events to ensure protection against a criticality accident. Thus, for these postulated accident conditions, the presence of additional soluble boron in the spent fuel pool water (above the 359 ppm required to maintain k_{eff} less than 0.95 under normal conditions) can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event.

Westinghouse Electric Company LLC calculations (Ref. 4) were performed to determine the amount of soluble boron required to offset the highest reactivity increase caused by these postulated accidents and to maintain k_{eff} less than or equal to 0.95. It was found that a spent fuel pool boron concentration of 910 ppm (assuming a conservatively low boron-10 atom percent of 19.4) was adequate to mitigate these postulated criticality related accidents and to maintain k_{eff} less than or equal to 0.95.

Specification 3.7.16 ensures the spent fuel pool contains adequate dissolved boron to compensate for the increased reactivity caused by a mispositioned fuel assembly or a loss of spent fuel pool cooling.

Specification 4.3 requires that the spent fuel rack k_{eff} be less than or equal to 0.95 when flooded with water borated to 400 ppm. This value was selected to provide a nominal margin above the calculated limiting value of 359 ppm. A spent fuel pool boron dilution analysis was performed which confirmed that sufficient time is available to detect and mitigate a dilution of the spent fuel pool before the 0.95 k_{eff} design basis is exceeded. The spent fuel pool boron dilution analysis concluded that sufficient time would be available for operators to recognize and terminate a dilution event that started at

BASES

APPLICABLE SAFETY ANALYSES (continued)	the spent fuel pool boron concentration of 1800 ppm and terminated at 750 ppm, providing significant margin to the 400 ppm value provided in Specification 4.3.1.1. When the requirements of Specification 3.7.17 are not met, immediate action must be taken to move any noncomplying fuel assembly to an acceptable location to preserve the double contingency principle assumption of the criticality accident analysis. The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The restrictions on the placement of fuel assemblies within the spent fuel pool, in accordance with Specification 4.3.1.1 and the accompanying LCO, ensure the k_{eff} of the spent fuel storage pool will always remain **<** 1.0 in unborated water and $\leq$ 0.95, with credit given for boron in the water.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the spent fuel storage pool.
ACTIONS	A.1 Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the configuration of fuel assemblies stored in the spent fuel storage pool is not in accordance with Specification 4.3.1.1, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Specification 4.3.1.1.

BASES

ACTIONS

A.1 (continued)

If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1

This SR verifies by administrative means that the fuel assembly, fuel insert, or other hardware is placed in the storage racks in accordance with Specification 4.3.1.1 and the accompanying LCO.

The Frequency of this SR is prior to storing or moving a fuel assembly.

SR 3.7.17.2

This SR verifies that the fuel assemblies and other hardware affected by a fuel handling campaign are placed in the spent fuel storage racks are stored in accordance with the requirements of LCO 3.7.17 and Specification 4.3.1.1. The intent of this SR is to ensure that the storage configuration following a spent fuel pool campaign was completed accurately. This SR helps ensure that storage arrays affected by the campaign will continue to meet subcriticality criteria of Specification 4.3.1.1.

The Frequency of this SR requires performance within 7 days after the completion of any fuel handling campaign which involves:

a. The relocation of fuel assemblies within the spent fuel pool;

b. The addition of fuel assemblies to the spent fuel pool; or

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.17.2 (continued)

c. The relocation of non-fuel materials in the spent fuel storage racks. Such materials include rod control cluster assemblies (RCCAs), failed fuel baskets, neutron source assemblies, and metal waste materials.

The extent of a fuel handling campaign will be defined by plant administrative procedures. Examples of a fuel handling campaign would include all the fuel handling performed during a refueling outage or associated with the placement of new fuel into the spent fuel pool.

The 7 day allowance for completion of this SR provides adequate time for completion of the spent fuel pool inventory verification while minimizing the time a fuel assembly may be misloaded in the spent fuel pool. The Frequency of this SR is based on providing timely verification without imposing interruption to the fuel handling processes during a defined fuel handling campaign. If a fuel assembly is misloaded during the fuel handling campaign, the minimum boron concentration required by LCO 3.7.16 will ensure that the spent fuel rack k_{eff} remains within limits until the spent fuel inventory verification is performed.

REFERENCES

1. USAR, Section 10.2.

2. ANSI/ANS-8.1-1983.

3. Nuclear Regulatory Commission, Letter to All Power Reactor Licensees from B. K. Grimes, “OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications”, April 14, 1978.

BASES

REFERENCES (continued)

4. "Prairie Island Units 1 and 2 Spent Fuel Pool Criticality Analysis", WCAP-17400-NP, Revision 0, Westinghouse Electric Company, July 2011.

5. Not used.

6. American Nuclear Society, "American National Standard Design Requirements for Light Water Reactor Fuel Storage Facilities at Nuclear Power Plants", ANSI/ANS-57.2-1983, October 7, 1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources-Operating

BASES

BACKGROUND

The unit 4 kV Safeguards Distribution System AC sources consist of the offsite power sources and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As required by AEC GDC Criterion 39 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Safeguards AC Distribution System is divided into redundant trains so that the loss of any one train does not prevent the minimum safety functions from being performed. Each train has two connections to the offsite power sources, and one to an onsite DG.

Offsite power is supplied to the unit switchyard(s) from the transmission network by five transmission lines. From the switchyard(s), electrically and physically separated paths provide AC power, through step down station auxiliary transformers, to the 4 kV safeguards buses. A detailed description of the offsite power network and the paths to the safeguards buses is found in Reference 2.

A path consists of all breakers, transformers, switches, cabling, and controls required to transmit power from the offsite transmission network to the safeguards bus(es).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Safeguards AC Distribution System under postulated worst case loading conditions. Within 1 minute after the load restore signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service via the load

BASES

BACKGROUND (continued)

sequencer. The transformers are capable of block loading (operation without load sequencing), when loading and motor starting is selectively restricted. Refer to Specification 3.3.4, "4kV Safeguards Bus Voltage Instrumentation" for additional actions prescribed for an inoperable load sequencer.

The onsite standby power source for each 4kV safeguards bus is a dedicated DG. For Unit 1, DGs 1 and 2 are dedicated to buses 15 and 16, respectively. For Unit 2, DGs 5 and 6 are dedicated to buses 25 and 26, respectively. A DG starts automatically on a safety injection (SI) signal (e.g., low pressurizer pressure or high containment pressure signals) or on a 4 kV safeguards bus degraded voltage or undervoltage signal (refer to LCO 3.3.4, “4 kV Safeguards Bus Voltage Instrumentation”). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of safeguards bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the safeguards bus on an SI signal alone. Following the trip of offsite power, a sequencer strips nonpermanent loads from the bus. When the DG is tied to the bus, loads are then sequentially connected to its respective bus by the automatic load sequencer. The sequencing logic controls the start permissive for motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of offsite power, the safeguards electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the load restore signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

BASES

BACKGROUND (continued)	Ratings for the Unit 1 DGs meet the intent of Safety Guide 9 and Unit 2 DGs satisfy the intent of Regulatory Guide 1.9, as discussed in the USAR (Ref. 2). The continuous service rating of each Unit 1 DG is 2750 kW with a 30 minute rating of 3250 kW. The continuous service rating of each Unit 2 DG is 5400 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The safeguards loads that are powered from the 4 kV safeguards buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the USAR (Ref. 3) 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 results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Two paths between the offsite transmission grid and the onsite 4 kV Safeguards Distribution System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

The paths are described in the USAR and are part of the licensing basis for the unit. There are four separate external power sources which provide multiple offsite network connections:

a. A reserve transformer (1R) from the 161 kV portion of the plant substation;

b. A second reserve transformer (2RS/2RY) from the 345 kV portion of the plant substation;

c. A cooling tower transformer (CT1/CT11) supplied from the 345 kV portion of the plant substation; and

d. A cooling tower transformer (CT12) supplied from a tertiary winding on the substation auto transformer.

Each path must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the safeguards buses. Plant procedures provide an assessment for the various configurations and requirements (e.g., loading, grid conditions, generator MVAR load, and etc.) for a path to be declared OPERABLE.

Each DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective safeguards bus on detection of bus undervoltage. The DG will be ready to load within 10 seconds following receipt of a start signal. Each DG must also be capable of accepting required loads within the assumed loading

BASES

LCO (continued)

sequence intervals, and continue to operate until offsite power can be restored to the safeguards 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 conditions.

Proper sequencing of loads is a required function for DG OPERABILITY.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, “AC Sources-Shutdown.”

The Load Sequencer requirements are covered in LCO 3.3.4, “4 kV Safeguards Bus Voltage Instrumentation”.

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provision of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with one path inoperable, it is necessary to verify the OPERABILITY of the remaining required path on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if the second path fails SR 3.8.1.1, there are no OPERABLE paths, and Condition C, for two paths inoperable, is entered.

A.2

Operation may continue in Condition A for a period that should not exceed 7 days. With one path inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE path and DGs are adequate to supply electrical power to the onsite Safeguards Distribution System.

The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered

BASES

ACTIONS

A.2 (continued)

while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 21 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 35 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the paths on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a path fails to pass SR 3.8.1.1, it is inoperable and additional Conditions and Required Actions apply.

BASES

ACTIONS (continued)

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

ACTIONS

B.2 (continued)

In this Condition, the remaining OPERABLE DG and paths are adequate to supply electrical power to the onsite Safeguards Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

According to the Maintenance Rule, 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

B.4

Operation may continue in Condition B for a period that should not exceed 14 days.

In Condition B, the remaining OPERABLE DG and paths are adequate to supply electrical power to the onsite Safeguards Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 21 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of 28 days) allowed prior to complete restoration of the LCO. The 21 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit

ACTIONS

B.4 (continued)

is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 21 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two paths are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is 12 hours. The rationale for the 12 hours is that a Completion Time of 24 hours is allowed for two paths inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains.

BASES

ACTIONS

C.1 and C.2 (continued)

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. Both paths are inoperable; and

b. A required feature on either train is inoperable.

If at any time during the existence of Condition C (two paths inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

Operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

With both of the required paths inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the paths commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

BASES

ACTIONS

C.1 and C.2 (continued)

With the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two paths are restored within 24 hours, unrestricted operation may continue. If only one path is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to either train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems-Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one path and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

Operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required paths). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since inadvertent generator trips could result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

With both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, as discussed in the USAR (Ref. 2). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with regulatory guidance as addressed in the USAR. The voltages and frequencies discussed in these SRs are consistent with analysis described in the USAR (Ref. 2).

SR 3.8.1.2, 3.8.1.6 and 3.8.1.9 make reference to DG steady state voltage. When required to start and connect to the bus, the connection of the DG to the safeguards bus is controlled by the automatic load sequencer. The load sequencer is a programmable logic controller (PLC) which performs the following functions for its associated safeguards bus: load rejection; voltage restoration; and load restoration. The voltage restoration portion of the sequence will connect the DG to the bus if no viable offsite source is available. The load restoration is accomplished by a series of start permissives separated by 5 second steps. The 5 second steps allow for the starting of the load and voltage recovery prior to starting the next loads which ensures that voltage does not fall below the degraded voltage setting of the bus. The PLC program has the capability to have up to 9 programed load steps which total 45 seconds. Along with a 15 second allowance for the DG to start and

BASES

SURVEILLANCE REQUIREMENTS (continued)

come up to rated speed and voltage gives a total transient time of 60 seconds. After 60 seconds the DG is determined to be in a steady state condition.

SR 3.8.1.1

This SR ensures proper circuit continuity for the required offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their offsite power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.6

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition. The steady state voltage requirement is to allow the DG to accept loads and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

In order to reduce stress and wear on diesel engines, some manufacturers recommend a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.6 (continued)

Since SR 3.8.1.6 requires a 10 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 is the intent of Note 1 of SR 3.8.1.2.

The 31 day Frequency for SR 3.8.1.2 and the 184 day Frequency for SR 3.8.1.6 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 with the offsite electrical system and accepting loads greater than or equal to 90% of the continuous rating of the DG (Ref. 2). The Unit 1 and Unit 2 diesel generators have different loading requirements since their individual loads are different. As an example, the Unit 2 diesel generators supply emergency power to the cooling water pump whereas the Unit 1 diesel generators do not. 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.

The 31 day Frequency for this Surveillance is consistent with SR 3.8.1.2.

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing loads or system

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

characteristics, do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from path or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at least 300 gallons (Unit 2 - 425 gallons). The limit switch ensures this level is maintained in the day tank. The level is selected to ensure adequate fuel oil for a minimum of 2 hours for Unit 1 (1 hour of DG operation at full load plus 10% for Unit 2).

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

SR 3.8.1.5

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

The design of fuel transfer systems is such that pumps operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. Therefore, a 31 day Frequency is appropriate.

SR 3.8.1.6

See SR 3.8.1.2.

SR 3.8.1.7

This Surveillance demonstrates the DG capability to reject a load equivalent to the largest single load without tripping. The DG load rejection may occur because of an inadvertent breaker tripping. This Surveillance ensures proper engine response under the simulated test conditions. This test simulates a load rejection and verifies that the DG does not trip upon loss of the largest single load.

The 24 month Frequency is consistent with the expected fuel cycle lengths.

SR 3.8.1.8

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on an actual or simulated safety injection (SI) signal. The noncritical trips are all the automatic trips except for a. engine overspeed;
b. generator differential current; and c. ground fault (Unit 1 only).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The Frequency is modified by a Note which allows the SR 3.0.2 interval extension (1.25 times the specified interval) to be applied to the interval for this SR, that is, this SR may be performed at an interval up to 30 months within the guidance of SR 3.0.2 for interval extensions. This is an exception to the limitations stated in SR 3.0.2 for SRs with a 24 month Frequency. The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.1.9

Demonstrate once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to 103 - 110% (100 – 110% for Unit 2) of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 24 month Frequency takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. The Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. Note 2 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.85. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 2 allows the Surveillance to be conducted as a power factor other than ≤ 0.85. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.85 results in voltages on the emergency buses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.85 while still maintaining acceptable voltage limits on the emergency buses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.85 may not cause unacceptable voltages on the emergency buses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained close as practicable to 0.85 without exceeding the DG excitation limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

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

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

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 months.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Note 3 is provided to allow D2 DG to be OPERABLE without requiring the 12 Battery Charger to be energized until completion of this SR during the Unit 1 2011 refueling outage.

SR 3.8.1.11

This Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies DG starts on the loss of offsite power. Tests of other design features associated with loss of offsite power are satisfied by SR 3.8.1.10.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs may be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 39, issued for comment July 10, 1967, as referenced in the USAR, Section 1.2.

2. Regulatory Guide 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants", Revision 3.

3. USAR, Section 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources-Shutdown

BASES

BACKGROUND

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

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

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

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

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODES 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

One path capable of supplying the onsite 4 kV Safeguards Distribution subsystem(s) of LCO 3.8.10, “Distribution Systems - Shutdown,” ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with the distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the path. Together, OPERABILITY of the required path and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The path must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Safeguards bus(es). Paths are those that are described in the USAR and are part of the licensing basis for the unit.

There are four separate external power sources which provide multiple offsite network connections:

a. A reserve transformer (1R) from the 161 kV portion of the plant substation;

b. A second reserve transformer (2RS/2RY) from the 345 kV portion of the plant substation;

c. A cooling tower transformer (CT1/CT11) supplied from the 345 kV portion of the plant substation; and

d. A cooling tower transformer (CT12) supplied from a tertiary winding on the substation auto transformer.

BASES

LCO (continued)

The DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective Safeguards bus on detection of bus undervoltage. The DG will be ready to load within 10 seconds of receiving a start signal. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the Safeguards buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot or DG in standby at ambient conditions.

Proper sequencing of loads is a required function for DG OPERABILITY.

It is acceptable for the operating unit to be cross tied to the shutdown unit, allowing an offsite power circuit to supply power to various equipment for the shutdown unit.

A Note has been added allowing the LCO not being applicable for a period of 8 hours during the performance of SR 3.8.1.10. This note was added for the sole purpose of performing SR 3.8.1.10 on both DGs at the same time. This is acceptable since the DG(s) are available for operation and the primary offsite source can be made available within a short time.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

The Load Sequencer requirements are covered in LCO 3.3.4, "4 kV Safeguards Bus Voltage Instrumentation".

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODES 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

<u>A.1, A.2, A.3, A.4, B.1, B.2, B.3, and B.4</u>

A required path would be considered inoperable if it were not available to at least one required Safeguards train. Although two trains may be required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement.

BASES

ACTIONS

A.1, A.2, A.3, A.4, B.1, B.2, B.3, and B.4 (continued)

With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

ACTIONS

A.1, A.2, A.3, A.4, B.1, B.2, B.3, and B.4 (continued)

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required Safeguards bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the path, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized train.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power grid or otherwise rendered inoperable during performance of SRs, and to preclude de-energizing a required 4 kV Safeguards bus or disconnecting a required path during performance of SRs. With limited AC sources available, a single event could compromise both the required path and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and required path is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil

BASES

BACKGROUND

Each diesel generator (DG) is provided with a stored DG fuel oil supply sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post design basis accident (DBA) load demand as discussed in the USAR (Ref. 1). The onsite fuel oil supply is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

New DG fuel oil is placed in a receiving tank where it is tested in accordance with the Prairie Island Nuclear Generation Plant (PINGP) Diesel Fuel Oil Testing Program. Once the test results have verified that the fuel oil is within limits, the fuel oil may be transferred to the safeguards fuel oil storage tanks. Fuel oil is then transferred from the safeguards fuel oil storage tank to the day tank by the fuel oil transfer pumps associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG.

For proper operation of the DGs, it is necessary to ensure the proper quality of the fuel oil. PINGP ensures fuel oil quality through implementation of the Diesel Fuel Oil Testing Program.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR (Ref. 2) assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Since the diesel fuel oil system supports the operation of the standby AC power sources, it satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Stored DG diesel fuel oil supply is required to have sufficient supply for 7 days of DG operation at maximum post DBA load demand. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the safeguards storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources-Operating," and LCO 3.8.2, "AC Sources-Shutdown."
APPLICABILITY	The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored DG fuel oil supply supports LCO 3.8.1 and LCO 3.8.2, it is required to be within limits when the associated DG is required to be OPERABLE.
ACTIONS	The ACTIONS Table is modified by a note indicating that separate Condition entry is allowed for each stored DG fuel oil supply. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable stored DG fuel oil supply. Complying with the Required Actions for one inoperable stored DG fuel oil supply may allow for continued operation, and subsequent inoperable stored DG fuel oil supply is governed by separate Condition entry and application of associated Required Actions.

BASES

ACTIONS (continued)

A.1

In this Condition, the 7 day stored DG fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil supply reductions that maintain at least a 6 day supply. The fuel oil supply equivalent to a 6 day supply is 23,625 gallons (Unit 2 – 36,479 gallons). These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required supply, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank(s). A period of 48 hours is considered sufficient to complete restoration of the required supply prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity ($\geq$ 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.2. If fuel oil properties in one or more required DG fuel oil tank(s) are not within limits, actions must be taken to restore the fuel oil properties to within limits. If the fuel oil properties in the fuel oil tank(s) are not within limits, it does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated it is prudent to allow a brief period prior to declaring the associated DG inoperable or isolating the associated fuel oil tank(s). Therefore the 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

BASES

ACTIONS (continued)

C.1

With a Required Action and associated Completion Time of Condition B not met, the associated fuel oil tank must be isolated within 2 hours. Isolation of a specific fuel oil tank may not make the associated DG inoperable since the DG can take suction from another fuel oil tank. Isolation of the associated fuel oil tank may cause entry into Conditions A or D which could result in the DG being inoperable.

D.1

With the stored fuel oil supply not within the limits specified or Required Actions and associated Completion Times of Conditions A or C not met, the DG may be incapable of performing the intended function and must be immediately declared inoperable.

A Note has been added to Condition D requiring entry into the applicable Conditions and Required Actions of LCO 3.7.8, “CL System” for CL train(s) made inoperable as a result of stored fuel oil properties not within limits. Since the diesel generators and the diesel driven CL pumps share a common storage tank, the diesel fuel oil properties are maintained by Specification 5.5.11, “Diesel Fuel Oil Testing Program.” Therefore, if the fuel oil properties are not within limits, both the diesel generators and the diesel driven CL pumps are affected and appropriate Required Actions taken.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate supply of DG fuel oil in the storage tanks to support DG operation for 7 days. The stored DG fuel oil supply equivalent to a 7 day supply is 27,351 gallons (Unit 2 – 42,272 gallons) when calculated in accordance with Regulatory Guide 1.137 (Ref. 3) and ANSI N195-1976 (Ref. 4). The required fuel storage volume is determined using the most limiting energy content of the stored fuel (Ref. 5 and 6). Using known correlation of diesel fuel oil absolute specific gravity or API gravity to energy content, the required diesel generator output, and the corresponding fuel consumption rate, the onsite fuel storage volume required for 7 days of operation can be determined. SR 3.8.3.2 requires new fuel to be tested to verify that the absolute specific gravity or API gravity is within the range assumed in the DG diesel fuel oil consumption calculations. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The Unit 1 fuel oil system has two safety related trains. Each train consists of two Design Class I fuel oil storage tanks for the same train DG. These two tanks are interconnected and normally aligned to supply the same train DG day tank. Any combination of inventory in these two tanks may be used to satisfy the supply requirements for the train's DG.

The Unit 2 DG fuel oil system has two safety related trains. Each train consists of two Design Class I fuel oil storage tanks for the same train DG. These two tanks are interconnected and normally aligned to supply the same train DG day tank. Any combination of inventory in these two Unit 2 tanks may be used to satisfy the supply requirements for the train's DG.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.2

The tests for the new fuel oil prior to addition into the safeguards storage tank(s) are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the safeguards storage tanks without concern for contaminating the entire volume of fuel oil in the safeguards storage tanks. These tests are to be conducted prior to adding the new fuel to the safeguards storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests and limits for new and stored fuel are described in the Diesel Fuel Oil Testing Program of Specification 5.5.11.

Failure to meet any of the limits specified in the Diesel Fuel Oil Testing Program is cause for rejection of the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks. Failure to meet any of the limits for stored fuel requires entry into Condition B.

REFERENCES

1. USAR, Sections 8.4.
2. USAR, Section 14.
3. Regulatory Guide 1.137, Revision 1.
4. ANSI N195-1976.
5. Calculation ENG-ME-020.
6. Calculation ENG-ME-066.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The DC safeguards electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and Reactor Protection Instrument AC Panel power (via inverters). As required by AEC GDC 39 (Ref. 1), the DC safeguards electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure.

The 125 VDC safeguards electrical power system consists of two independent and redundant safety related DC safeguards electrical power subsystems (Train A and Train B). Each subsystem consists of a 125 VDC battery, a battery charger, and all the associated control equipment and interconnecting cabling.

There is one portable battery charger, which can provide backup service in the event that a stationary battery charger is out of service. If the portable battery charger is substituted for the stationary battery charger, then the requirements of independence and redundancy between subsystems are maintained.

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In the case of loss of all AC power to the battery chargers, the DC system voltage is automatically powered from the station batteries until the AC power is restored to the battery chargers.

BASES

BACKGROUND (continued)

The Train A and Train B DC safeguards electrical power subsystems provide the control power for their associated safeguards AC power load group, 4.16 kV switchgear, and 480 V switchgear. The DC safeguards electrical power subsystems also provide backup DC electrical power to the inverters, which in turn power the Reactor Protection Instrument AC Panels.

The DC safeguards power distribution system is described in more detail in Bases for LCO 3.8.9, “Distribution System - Operating,” and LCO 3.8.10, “Distribution Systems - Shutdown.”

Each 125 VDC battery is separately housed in a ventilated room with its charger and main DC distribution panels. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant safeguards DC subsystems, such as batteries, battery chargers, or distribution panels.

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in the USAR (Ref. 2). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for Train A and Train B DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design terminal voltage limit for each battery, which ranges from approximately 110 to 111 V, is provided in the USAR (Ref. 2).

BASES

BACKGROUND (continued)

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 V for a 58 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.065 Vpc, the battery cell will maintain its capacity greater than 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. A nominal float voltage of 2.23 Vpc corresponds to a total float voltage output of 129.4 V for a 58 cell battery.

Each Train A and Train B DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery fully charged. Each battery charger also has sufficient excess capacity to restore the battery to its fully charged state within 24 hours while supplying normal steady state loads discussed in the USAR (Ref. 2).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge

BASES

BACKGROUND (continued)

characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, (Ref. 3), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC safeguards electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

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

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

b. A worst-case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii)

BASES (continued)

LCO

The DC safeguards electrical power subsystem, each subsystem consisting of a battery, battery charger and the corresponding control equipment and interconnecting cabling, supplying power to the associated panel within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC safeguards electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 2).

An OPERABLE DC safeguards electrical power subsystem requires the battery and a respective charger to be operating and connected to the associated DC panel.

APPLICABILITY

The DC safeguards electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, “DC Sources - Shutdown.”

BASES (continued)

ACTIONS

A.1, A.2, A.3, and A.4

Condition A represents one battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). Required Actions A.1 and A.2 verify that the associated battery and other train charger are OPERABLE within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or verifying that the associated battery and other train charger are OPERABLE and no loss of function exists.

Required Action A.3 requires, within 2 hours, that the diesel generator and safeguards equipment on the other train are verified to be OPERABLE. This verification ensures that the redundant train is OPERABLE ensuring that the plant will be able to mitigate an event as analyzed in the USAR (Ref. 3).

Required Action A.4 limits the restoration time for the inoperable battery charger to 8 hours. The 8 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1, B.2, B.3, and B.4

Condition B represents one battery inoperable. With one battery inoperable, the DC bus is being supplied by the OPERABLE battery charger. Any event that results in a loss of the AC bus supporting the battery charger will also result in loss of DC to that train. Recovery of the AC bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon the battery. Required Actions B.1, B.2, and B.3

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

verify that the associated battery charger, the other train battery and associated charger are OPERABLE within 2 hours. This time provides for either returning the inoperable battery to OPERABLE status or verifying that the associated charger and other train battery and charger are OPERABLE therefore, ensuring no loss of function exists.

Required Action B.4 requires the inoperable battery to be restored to OPERABLE within 8 hours. The 8 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

C.1

Condition C represents one train with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required DC electrical power subsystems is inoperable for reasons other than Condition A or B (e.g., inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems to mitigate a worst

BASES

ACTIONS

C.1 (continued)

case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

D.1 and D.2

If the inoperable DC safeguards electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 5 is consistent with other standard shutdown conditions.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.20 Vpc or 128 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is consistent with manufacturer recommendations.

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. The battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 250 amps at the minimum established float voltage for 4 hours. The ampere requirements are based on the USAR (Ref. 2). The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

The other option requires that each battery charger be capable of recharging the battery after a discharge test coincident with supplying the demands of the various continuous steady state loads, after the battery discharge to the bounding design basis event discharge state. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is fully recharged when the measured charging current is ≤ 2 amps.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.3

A battery service test is a special test of the battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 2.

The battery service test should be performed during refueling operations, or at some other outage, with intervals between tests not to exceed 24 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits." Criterion 39, issued for comment July 10, 1976, as referenced in USAR, Section 1.2.

2. USAR, Section 8.

3. USAR, Section 6.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for LCO 3.8.4, “DC Sources - Operating.”
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR (Ref. 1) and (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many DBAs that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODES 1, 2, 3, and 4 LCO requirements are acceptable during shutdown MODES based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The DC electrical power subsystem, consisting of a battery one battery charger, and the corresponding control equipment, and interconnecting cabling within the train, is required to be OPERABLE to support one train of the distribution systems required OPERABLE by LCO 3.8.10, “Distribution Systems - Shutdown.” This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

A Note has been added to the LCO allowing the service building DC electrical power subsystem components to be used in lieu of the required safeguards DC electrical power subsystem components when the required safeguards DC electrical power subsystem is inoperable due to testing, maintenance, or replacement. The service building DC power electrical components include the battery, associated battery charger, and the interconnecting cabling. When any of the service building DC power electrical components are used in lieu of the safeguards DC electrical power subsystem components, they are required to be maintained in accordance with Specification 5.5.15 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, “IEEE Recommended Practice For Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries For Stationary Applications” (Ref. 3).

BASES (continued)

APPLICABILITY

The DC electrical power source required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

BASES

ACTIONS (continued)

A.1

Condition A represents one train with one required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained).

Required Action A.1 limits the restoration time for the inoperable battery charger to 8 hours. The 8 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1, B.2, B.3, and B.4

Condition B represents one train with one required DC electrical power subsystem inoperable for reasons other than Condition A or if the Required Actions and associated Completion Time of Condition A are not met. In this Condition there may not be adequate DC power available to support the subsystems required by LCO 3.8.10. Therefore, conservative actions are required (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions) that assure the minimum SDM or boron concentration limit is met to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystem and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. USAR Section 6.

2. SAR Section 14.

3. IEEE-450-1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the DC power subsystem batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, “DC Sources - Operating,” and LCO 3.8.5, “DC Sources-Shutdown.” In addition to the limitations of this Specification, the plant procedures also implement a program specified in Specification 5.5.15 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, “IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications” (Ref. 1).

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 V for 58 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.065 Vpc, the battery cell will maintain its capacity for greater than 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.23 Vpc corresponds to a total float voltage output of 129.4 V for a 58 cell battery.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR (Ref. 2) and (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of:

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

b. A worst-case single failure.

Battery parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after a loss of all AC power. This ensures that adequate DC power is available for starting the emergency diesel generators and for other emergency uses. The batteries provide this required DC power until AC power is restored to the battery chargers via the diesel generators. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the plant procedures is conducted as specified in Specification 5.5.15.

BASES (continued)

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the battery is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

A Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each battery. This is acceptable, since Required Actions for each Condition provide appropriate compensatory actions.

<u>A.1, A.2, and A.3</u>

With one or more cells in one battery < 2.07 V, the battery cell is degraded. Within 8 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one battery < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify “perform,” a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.8.6.1 is failed then there may not be assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

BASES

ACTIONS (continued)

B.1 and B.2

One battery with float > 2 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 8 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addresses charger inoperability. If the charger is operating in the current limit mode after 8 hours that is an indication that the battery has been substantially discharged. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 24 hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 V, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 V there is good assurance that, within 24 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

BASES

ACTIONS

B.1 and B.2 (continued)

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 24 hours, avoiding a premature shutdown with its own attendant risk and the battery is not inoperable.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 24 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

C.1, C.2, and C.3

With one battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.15, Battery Monitoring and Maintenance Program). They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.15.b item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cells replaced.

D.1

With one battery with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

BASES

ACTIONS (continued)

E.1

With batteries in the redundant trains with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one train within 8 hours.

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, sufficient capacity to supply the design load requirement is not assured and the corresponding battery must be declared inoperable. Additionally, discovering one or more batteries in one train with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1 (continued)

battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 1). The 7 day Frequency is consistent with IEEE-450 (Ref. 1).

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 128 V at the battery terminals, or 2.20 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.15. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V. The Frequency for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell is consistent with IEEE-450 (Ref. 1).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450 (Ref. 1).

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60EF). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 1).

SR 3.8.6.6

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

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

It may consist of just two rates; for instance the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1) and IEEE-485 (Ref. 4). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet or exceed the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's ratings. Degradation is indicated, according to IEEE-450 (Ref. 1), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 1).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

REFERENCES

1. IEEE-450-1995.
2. USAR, Chapter 8.
3. USAR, Chapter 14.
4. IEEE-485-1983, June 1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters-Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the Reactor Protection Instrument AC Panels because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the Reactor Protection Instrument AC Panels. The inverters can be powered from an internal AC source/rectifier or the DC system. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Engineered Safety Feature Actuation System (ESFAS)(Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR (Ref. 2) assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required Reactor Protection Instrument AC Panels OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

Inverters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters ensure an uninterruptible supply of AC electrical power to the Reactor Protection Instrument AC panels even if the 4 kV Safeguards buses are de-energized.

OPERABLE inverters require the associated Reactor Protection Instrument AC panel to be powered by the inverter with output voltage supply to the inverter from the 125 Volt DC system. Normally, the power supply is from an internal AC source via rectifier with the station battery available as the uninterruptible power supply.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, “Inverters-Shutdown.”

BASES (continued)

ACTIONS

A.1 and A.2

With one Reactor Protection Instrument AC inverter inoperable, Required Action A.1 and A.2 require verification, within 2 hours, the Reactor Protection Instrument AC panel with an inoperable inverter is powered from Panel 117 (Unit 2 - 217) or verify that the Reactor Protection Instrument AC panel with an inoperable inverter is powered from its inverter bypass source.

Plant design provides acceptable alternate methods of powering a Reactor Protection Instrument AC panel with an inoperable inverter. Panel 117 (Unit 2 - Panel 217), by plant design, can provide reliable power to a Reactor Protection Instrument AC panel. Alternatively, a Reactor Protection Instrument AC panel may be powered by an inverter internal bypass. In the event an inverter becomes inoperable, the inverter static transfer bypass switch will automatically bypass, thus providing power to the associated Reactor Protection Instrument AC panel and maintain OPERABILITY. Required Actions A.1 and A.2 require verification that only one Reactor Protection Instrument AC panel is powered from Panel 117 (Unit 2 - Panel 217) or an inverter bypass source. This verification must be completed within 2 hours.

B.1, B.2, and B.3

With two Reactor Protection Instrument AC inverters inoperable, the associated Reactor Protection Instrument AC panels are considered to be inoperable unless they are energized from Panel 117 (Unit 2 - Panel 217) or they are automatically re-energized by their inverter static transfer switch.

For this reason a Note has been included in Condition B requiring the entry into the Conditions and Required Actions of LCO 3.8.9,

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

"Distribution Systems — Operating." This ensures that the Reactor Protection Instrument AC panel is re-energized within 2 hours. Plant design provides acceptable alternate methods of powering Reactor Protection Instrument AC panels with an inoperable inverter. Panel 117 (Unit 2 - Panel 217), by plant design, can provide reliable power to a Reactor Protection Instrument AC panel. Alternatively, a Reactor Protection Instrument AC panel may be powered by an inverter internal bypass. In the event an inverter becomes inoperable, the inverter static transfer bypass switch will automatically bypass, thus providing power to the associated Reactor Protection Instrument AC panel and maintain OPERABILITY. Therefore, based on plant design, Required Actions B.1 and B.2 require verification that no more than one Reactor Protection Instrument AC inverter will be powered from Panel 117 (Unit 2 - Panel 217) and one or both Reactor Protection Instrument AC panel(s) are powered from an inverter bypass source. This verification must be completed within 2 hours.

Required Action B.3 allows 8 hours to fix the inoperable inverter and return it to service. The 8 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the Reactor Protection Instrument AC panel is powered from its alternate source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the Reactor Protection Instrument AC panel is the preferred source for powering instrumentation trip setpoint devices.

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and Reactor Protection Instrument AC panels energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the Reactor Protection Instrument AC panels. 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. USAR, Section 8.
2. USAR, Section 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters-Shutdown

BASES

BACKGROUND	A description of the inverters is provided in the Bases for LCO 3.8.7, “Inverters-Operating.”
APPLICABLE SAFETY ANALYSES	The OPERABILITY of the inverter to the Reactor Protection Instrumentation AC panel during MODES 5 and 6 ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident. In general, when the unit is shutdown, the Technical Specification requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODES 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBA which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is

BASES

APPLICABLE SAFETY ANALYSES (continued)	required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management" as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications. The inverters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	At least one Reactor Protection Instrument AC panel energized by a battery backed inverter provides uninterruptible supply of AC electrical power to at least one Reactor Protection Instrument AC panel even if the 4 kV safeguards buses are de-energized. This ensures the availability of sufficient inverter power to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).
APPLICABILITY	The inverter required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provides assurance that: a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core; b. Systems needed to mitigate a fuel handling accident are available; c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODES 5 and 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2, A.3, and A.4

If the required inverter is inoperable, the remaining OPERABLE Reactor Protection Instrument AC panel power supplies as required by LCO 3.8.10, “Distribution Systems-Shutdown,” may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, or operations with a potential for positive reactivity additions. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)).

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverter and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverter should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the required inverter is functioning properly with all required circuit breakers closed and Reactor

BASES

SURVEILLANCE REQUIREMENTS	SR 3.8.8.1 (continued) Protection Instrument AC panel energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the Reactor Protection Instrument AC panel. The 7 day Frequency takes into account the reliability of the instrument panel power sources and other indications available in the control room that alert the operator to malfunctions.
REFERENCES	None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems-Operating

BASES

BACKGROUND

The onsite safeguards AC and DC electrical power distribution systems are divided by train into two redundant and independent electrical power distribution subsystems. The onsite Reactor Protection Instrument AC Distribution System is divided by channels into four separate subsystems (Ref. 1).

Each AC electrical power subsystem consists of a safeguards 4 kV bus and two 480 V buses. These in turn supply power to distribution panels and motor control centers (MCCs). Each safeguards 4 kV bus has two offsite sources of power as well as a dedicated onsite diesel generator (DG) source. Each safeguards 4 kV bus is normally connected to an offsite source. After a loss of this offsite power source, a transfer to the alternate offsite source is accomplished by a load sequencer, initiated by bus undervoltage relays. If all offsite sources are unavailable, the onsite emergency DG supplies power to the safeguards 4 kV bus. Control power for the 4 kV and 480 V bus breakers is supplied from the safeguards DC distribution system. Additional description of the safeguards AC system may be found in the Bases for LCO 3.3.4, “4 kV Safeguards Bus Voltage Instrumentation,” and the Bases for LCO 3.8.1, “AC Sources-Operating.”

The AC electrical power distribution system for each train includes the safety related buses and MCCs shown in Table B 3.8.9-1.

The 120 V Reactor Protection Instrument AC panels are arranged in four load groups and are normally powered from inverters. An alternate power supply for the instrument panels is the inverter bypass transformer powered from the same MCC as the associated inverter. Another alternate power supply is from the unit 208/120

BASES

BACKGROUND (continued)

VAC interruptable panel. Use of these supplies is governed by LCO 3.8.7, "Inverters-Operating."

There are two independent 125 VDC electrical power distribution subsystems (one for each train). The 125 VDC safeguards electrical power system consists of two independent and redundant safety related DC safeguards electrical power subsystems (Train A and Train B). The sources for each train are a 125 VDC battery, a battery charger, and all the associated control equipment and interconnecting cabling.

The list of the required Reactor Protection Instrument AC and safeguards DC distribution panels is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR (Ref. 2) assume ESF systems are OPERABLE. The safeguards AC, DC, and Reactor Protection Instrument AC 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 safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power; and

b. A worst case single failure.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of safeguards AC, DC, and Reactor Protection Instrument AC 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 safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Train A and Train B safeguards AC and DC, and Reactor Protection Instrument AC 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. This does not preclude redundant safeguards 4 kV buses from being powered from the same offsite path.

OPERABLE AC electrical power distribution subsystems require the associated buses and MCCs to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated panels to be energized to their proper voltage from either the associated battery or charger. OPERABLE Reactor Protection Instrument AC electrical power distribution subsystems require the associated panels to be energized to their proper voltage.

BASES (continued)

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems-Shutdown."

ACTIONS

A.1

With one or more safeguards AC electrical power distribution subsystems, 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, required safeguards AC electrical power, distribution subsystems to be restored to OPERABLE status within 8 hours.

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

BASES

ACTIONS

A.1 (continued)

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

Required Action A.1 is modified by a Note that requires the applicable Conditions and Required Actions of LCO 3.8.4, “DC Sources - Operating,” to be entered for DC trains made inoperable by inoperable AC power distribution subsystems. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. Inoperability of a distribution system can result in loss of charging power to batteries and eventual loss of DC power. This Note ensures that the appropriate attention is given to restoring charging power to batteries, if necessary, after loss of distribution systems.

BASES

ACTIONS (continued)

B.1

With one or more safeguards DC electrical power distribution subsystem panel(s) inoperable, the remaining safeguards DC electrical power distribution subsystem is 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 safeguards DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC panels must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery, charger, or portable charger.

The worst case scenario is one train without safeguards DC power; potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

BASES

ACTIONS

B.1 (continued)

c. The potential for an event in conjunction with a single failure of a redundant component.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With one Reactor Protection Instrument AC panel inoperable, the remaining OPERABLE Reactor Protection Instrument AC panels are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum ESF functions not being supported. Therefore, the required Reactor Protection Instrument AC panel must be restored to OPERABLE status within 2 hours by powering the panel from the associated inverter , inverter bypass transformer, or interruptible panel.

BASES

ACTIONS

C.1 (continued)

Condition C represents one Reactor Protection Instrument AC panel without power. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining instrument panels and restoring power to the affected instrument panel.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate instrument AC power. Taking exception to LCO 3.0.2 for components without adequate instrument AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without adequate instrument AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the Reactor Protection Instrument AC panel to OPERABLE status, the redundant capability afforded by the other OPERABLE instrument panels, and the low probability of a DBA occurring during this period.

BASES

ACTIONS

C.1 (continued)

The second Completion Time for Required Action C.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

E.1

Condition E addresses two trains with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised. Condition E also addresses two or more Reactor Protection Instrument AC panels inoperable. If the plant is in this Condition, an immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution systems, presented in Table B.3.8.9-1, are functioning properly, with the correct circuit breaker and switch alignment. The correct breaker and switch alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required subsystem. The verification of proper voltage ensures that the required voltage is readily available for motive as well as control functions for critical system loads. Various indications are available to the operators which demonstrate correct voltage for the subsystems. The 7 day Frequency takes into account the redundant capability of the safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. USAR, Section 8.
2. USAR, Section 14.

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

TYPE	DISTRIBUTION EQUIPMENT	UNIT 1 TRAIN A AND B	UNIT 2 TRAIN A AND B
Safeguards AC	4 kV Buses	15, 16	25, 26
	480 V Buses	111, 112, 121, 122	211, 212, 221, 222
	Motor Control Centers	1A1, 1A2 1AB1*, 1AB2* 1AC1, 1AC2 1K1, 1K2, 1KA2 1L1, 1L2 1LA1, 1LA2 1M1, 1M2 1MA1*, 1MA2* 1R1, 1S1 1T1*, 1T2* 1TA1, 1TA2 1X1, 1X2	2A1, 2A2 1AB1*, 1AB2* 2AC1, 2AC2 2K1, 2K2, 2KA2 2L1, 2L2 2LA1, 2LA2 2M1, 2M2 1MA1*, 1MA2* 2R1, 2S1 1T1*, 1T2* 2TA1, 2TA2 2X1, 2X2
Safeguards DC	125 VDC Panels	11, 12 15, 16 14*, 19* 17*, 18* 151, 161 152, 162 153, 163 191	21, 22 25, 26 14*, 19* 17*, 18* 27, 28 251, 261 252, 262 253, 263
Reactor Protection Instrument AC	120 VAC Panels	111, 112, 113, 114	211, 212, 213, 214

* Denotes MCC's or Panels that are transferable between units.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems-Shutdown

BASES

BACKGROUND

A description of the safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems-Operating."

In addition to the safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution systems listed in Table B 3.8.9-1, the following are examples of alternate power distribution equipment that may also be used during plant shutdown:

a. 4kV bus ties;

b. 480V alternate feeds;

c. Uninterruptable Panel 117 (217 for Unit 2);

d. Uninterruptable Panel 117 to 217 cross tie; and

e. Service Building DC to Safeguards DC cross tie.

This alternate equipment may be used to maintain reliable power to various plant systems and equipment that are required to be OPERABLE to support shutdown conditions. This equipment, when used as an alternate source, comes from the safeguards systems or sources from the other unit (except for Service Building DC to Safeguards DC cross tie which is neither from safeguards systems nor the other unit). Use of these systems or sources has been evaluated and does not have a detrimental impact on the other operating unit.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

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

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

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODES 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

The safeguards AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system, as presented in Table B 3.8.9-1, necessary to support OPERABILITY of required systems, equipment, and components - all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY. In addition, the alternate equipment described in the Background Section may be used to maintain OPERABILITY of the Electrical Distribution subsystems.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

The safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9

BASES (continued)

ACTIONS

LCO 3.0.3 is not applicable while in MODES 5 and 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)). Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to not result in reducing core reactivity below the required SDM or refueling boron concentration limit.

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required safeguards AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring the associated RHR inoperable, which results in taking the appropriate RHR actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the safeguards AC, DC, and Reactor Protection Instrument AC electrical power distribution subsystems are functioning properly, with the required buses and panels energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

None.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS) and the refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration and associated shutdown margin limits are specified in the COLR. The required boron concentration will vary depending on time in core life. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

AEC GDC Criterion 27 (Ref. 1) requires that two independent reactivity control systems of different design principles be provided. AEC GDC Criterion 29 (Ref. 1) requires at least one of these systems must be capable of holding the reactor core subcritical under any condition. The Chemical and Volume Control System (CVCS), Safety Injection (SI) and Residual Heat Removal (RHR) are the systems capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling cavity is then flooded with borated water from the refueling water storage

BASES

BACKGROUND (continued)	tank through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps. The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added boric acid with the water. The RHR System is in operation during refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS and the refueling cavity above the appropriate COLR limits.
APPLICABLE SAFETY ANALYSES	During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis for MODE 6. The boron concentration limits specified in the COLR are based on the core reactivity at one or more points in the fuel cycle and include an uncertainty allowance. The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, an adequate margin of safety is established during refueling. During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes. The analyzed boron dilution accident requiring the highest boron concentration occurs in MODE 6 (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).
LCO	The LCO requires that a minimum boron concentration be maintained in the RCS and the refueling cavity while in MODE 6. The boron concentration limits specified in the COLR ensure that a core k_{eff} of ≤ 0.95 or other lower value is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.
APPLICABILITY	This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a k_{eff} of ≤ 0.95 or a lower value based on the dilution analysis. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical. The Applicability is modified by a Note. The Note states that the limits on boron concentration are only applicable to the refueling cavity when connected to the RCS. When the refueling cavity is isolated from the RCS, no potential path for boron dilution exists.
ACTIONS	<u>A.1 and A.2</u> Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS or the refueling cavity, when connected, is less than that needed to maintain shutdown margin within its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be

BASES

ACTIONS

A.1 and A.2 (continued)

suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position.

Operations that individually add limited positive reactivity (e.g., temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS, and connected portions of the refueling cavity, is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to re-connecting portions of the refueling cavity to the RCS, this SR must be met per SR 3.0.4. If any dilution activity has occurred while the cavity was disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS.

A minimum Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. AEC “General Design Criteria for Nuclear Power Plant Construction Permits,” Criteria 27 and 29, issued for comment July 10, 1967, as referenced in USAR, Section 1.2.

2. USAR, Chapter 14.4.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, fuel transfer canal, refueling cavity, and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 2 and 4). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 50.67 limits or the NRC staff approved licensing basis (e.g., specified fraction of 10 CFR 50.67 limits).

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies, the water level in the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Reference 1. A minimum water level of 23 ft (Reference 1) allows a decontamination factor of 200 (Reference 4) to be used in the accident analysis for iodine. This relates to the assumption that 99.5% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain the total fuel rod iodine inventories provided in Reference 1.

The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 50 hours prior to fuel handling, the analysis demonstrates that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits. (Refs. 3 and 4).

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

BASES (continued)

LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits.
APPLICABILITY	LCO 3.9.2 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.15, "Spent Fuel Storage Pool Water Level."
ACTIONS	A.1 With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement shall not preclude completion of movement of a fuel assembly to a safe position.
SURVEILLANCE REQUIREMENTS	SR 3.9.2.1 Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1 (continued)

flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.183, July, 2000.
2. USAR, Section 14.5.
3. 10 CFR 50.67.
4. License Amendment Request dated January 20, 2004, "Selective Scope Implementation of Alternative Source Term for Fuel Handling Accident Applied to Containment Technical Specifications."

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

Core subcritical neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed core subcritical neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors (N-31, N-32, N-51, and N-52) are located external to the reactor vessel and detect neutrons leaking from the core.

The installed core subcritical neutron flux monitors are:

a. BF3 detectors operating in the proportional region of the gas filled detector characteristic curve; or

b. Fission chambers.

The detectors monitor the neutron flux in counts per second. The instrument range used for monitoring changes in subcritical multiplication typically covers six decades of neutron flux. The detectors provide continuous visual indication in the control room. The installed BF3 neutron flux monitors provide an audible indication to alert operators in containment to a possible dilution accident. The NIS is designed in accordance with the criteria presented in Reference 1.

APPLICABLE SAFETY ANALYSES

Two OPERABLE core subcritical neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly.

The core subcritical neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO	This LCO requires that two core subcritical neutron flux monitors, capable of monitoring subcritical neutron flux, be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. Neutron detectors N-31, N-32, N-51 and N-52 may be used to satisfy this LCO requirement. This LCO also requires that one audible countrate circuit, associated with either N-31 or N-32, be OPERABLE to ensure that audible indication is available to alert the operator in containment in the event of a dilution accident or improperly loaded fuel assembly.
APPLICABILITY	In MODE 6, the core subcritical neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, the installed detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."
ACTIONS	A1 and A.2 With only one required core subcritical neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 must be suspended immediately. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

BASES

ACTIONS

A.1 and A.2 (continued)

Introduction of temperature changes, including temperature increases when operating with a positive moderator temperature coefficient (MTC), must also be evaluated to not result in reducing SDM below the required value. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no required core subcritical neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a required core subcritical neutron flux monitor is restored to OPERABLE status.

B.2

With no required core subcritical neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions that could lead to reducing SDM below the required value are not to be made, the core reactivity condition is stabilized until the core subcritical neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

BASES

ACTIONS (continued)

C.1 and C2

With no audible core subcritical neutron flux monitor count rate circuit OPERABLE, only visual indication is available and prompt and definite indication of a boron dilution event would be lost. In this situation, the boron dilution event may not be detected quickly enough to assure sufficient time is available for operators to manually isolate the unborated water source and stop the dilution prior to the loss of SHUTDOWN MARGIN. Therefore, action must be taken to prevent an inadvertent boron dilution event from occurring. This is accomplished by isolating all the unborated water flow paths to the Reactor Coolant System. Isolating these flow paths ensures that an inadvertent dilution of the reactor coolant boron concentration is prevented. Since CORE ALTERATIONS and addition of unborated water can not be made, the core reactivity is stabilized until the audible count rate capability is restored.

The Completion Time of "Immediately" assures prompt response by operation and requires an operator to initiate actions to isolate an affected flow path immediately. Performance of Required Actions C.1 and C.2 shall not preclude completion of movement of a component to a safe position. Once actions are initiated, they must be continued until all the necessary flow paths are isolated or the circuit is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK of required channels, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.3.1 (continued) The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1. SR 3.9.3.2 SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION of required channels every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed.
REFERENCES	1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criteria 13, 19, 27 and 31, issued for comment July 10, 1967, as referenced in USAR Section 1.2. 2. USAR, Section 14.4.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Decay Time

BASES

BACKGROUND	The primary purpose of the decay time requirement is to ensure that the fission product inventories assumed in the fuel handling accident analyses are met. As soon as the reactor is subcritical, the quantity of fission products in the core decreases as the fission products undergo natural radioactive decay. As long as the reactor remains subcritical, this decrease will continue and the radiation levels will also decrease. In addition, to minimize personnel radiation exposures during refueling operations, it is necessary to allow the fission products to decay for an appropriate time. The fuel handling accident analyses assume that the accident occurs at least 50 hours after plant shutdown. Specifically, the fission product inventory is assumed to decay for 50 hours during the interval between reactor shutdown and movement of assemblies from the reactor core.
APPLICABLE SAFETY ANALYSES	The fuel handling accident is a design basis accident which considers an accident within the reactor core or the Spent Fuel Pool. Since the fuel removed from the reactor following reactor shut down is the most recently irradiated fuel, the fuel handling accident during movement of irradiated fuel within the reactor core is the limiting case. The fuel handling accident within the reactor core and the Spent Fuel Pool are assumed to occur after the fuel has decayed for 50 hours. The fuel handling accidents were analyzed using the Alternative Source Term methodology governed by 10 CFR 50.67 and the guidelines of Regulatory Guide 1.183 (Reference 1). The radiological consequences of the FHA using the AST methodology are well within the dose limits in 10 CFR 50.67 and meet the

BASES

APPLICABLE SAFETY ANALYSES (continued)	acceptance criteria of RG 1.183 for the exclusion area boundary (EAB), low population zone (LPZ) and the control room (Reference 2). Decay time satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The specified decay time limit requires the reactor to be subcritical for at least 50 hours. Implicit in this Technical Specification is the Applicability (during movement of irradiated fuel within the reactor core). This ensures that sufficient time has elapsed to allow the radioactive decay of the short-lived fission products, thus reducing the fission product inventory and reducing the effects of a fuel handling accident.
APPLICABILITY	The decay time restriction is applicable only during movement of irradiated fuel within the reactor core following a reactor shutdown. Once this restriction is met for a reactor core following shutdown, the fuel removed from the core and transferred to the Spent Fuel Pool will also meet the decay time restrictions. Thus all subsequent movements of irradiated fuel will meet the 50 hour decay time limit and be consistent with the fuel handling accident assumptions.

BASES (continued)

ACTIONS

A.1

With the reactor subcritical less than 50 hours, all movement of irradiated fuel within the reactor core must be suspended immediately. Movement of irradiated fuel within the reactor core is prohibited during the first 50 hours following reactor shutdown since the plant is not analyzed for a fuel handling accident during this period.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

Since movement of irradiated fuel within the reactor core is prohibited during the first 50 hours following reactor shutdown, a verification of time subcritical must be made prior to movement of irradiated fuel within the reactor core. This is done by confirming the time and date of subcriticality, and verifying that at least 50 hours have elapsed. The Frequency of “once prior to movement of irradiated fuel in the reactor core” ensures operation within the design basis assumption for decay time in the refueling accident analysis.

REFERENCES

1. RG 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors

2. USAR, Section 14.5.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation-High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), to provide mixing of borated coolant, and to prevent boron stratification. Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg. Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel which would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 20 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit de-energizing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier.

The RHR System, during refueling conditions, satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 20 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability.

At least one RHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes a RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to a RCS cold leg.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to meet the minimum boron concentration of LCO 3.9.1. Boron concentration reduction, with coolant at boron concentrations less than required to assure the RCS boron concentration is maintained, is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

BASES (continued)

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 20 ft above the top of the reactor vessel flange, to provide decay heat removal. The 20 ft water level was selected because it provides backup capability for heat removal.

Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level < 20 ft are located in LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations.

Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes, including temperature increases when operating with a positive moderator temperature coefficient (MTC), must also be evaluated to not result in reducing core reactivity below the required SDM or refueling boron concentration limit.

BASES

ACTIONS (continued)

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 20 ft above the reactor vessel flange provides an adequate available heat sink.

Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

In accordance with LCO 3.9.2, “Refueling Cavity Water Level,” movement of irradiated fuel within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 20 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4, A.5, A.6.1, and A.6.2

If no RHR loop is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with four bolts;

BASES

ACTIONS

A.4, A.5, A.6.1, and A.6.2 (continued)

b. One door in each air lock must be closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Ventilation Isolation System.

With the RHR loop requirements not met, the potential exists for the coolant to boil, clad to fail, and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows adequate time to fulfill the Required Actions and not exceed dose limits.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that the RHR loop is in operation in order to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

None.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), to provide mixing of borated coolant, and to prevent boron stratification. Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg. Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.
APPLICABLE SAFETY ANALYSES	If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel, which could eventually challenge the integrity of the fuel cladding, a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge. The RHR System, during refueling conditions, satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).
LCO	In MODE 6, with the water level < 20 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order to provide:

BASES

LCO (continued)

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold leg.

Either RHR pump may be aligned to the Refueling Water Storage Tank (RWST) to support filling or draining the refueling cavity or for performance of required testing.

The LCO contains two Notes which provide clarification of the LCO.

Note 1 permits the RHR pumps to be de-energized for up to 1 hour per 8 hour period. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and the core outlet temperature is maintained > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of 2 hours provided the other loop is OPERABLE and in operation. Prior to declaring the loop inoperable, consideration should be given to the existing plant configuration. This consideration should include that the core time to boil is short, there is no draining operation to further reduce RCS water level and that the capability exists to inject borated water into the reactor vessel. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

BASES (continued)

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 20 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level ≥ 20 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level."

ACTIONS

A.1 and A.2

If less than the required number of RHR loop(s) are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 20 ft of water level is established above the reactor vessel flange. When the water level is ≥ 20 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes,

BASES

ACTIONS

B.1 (continued)

including temperature increases when operating with a positive moderator temperature coefficient (MTC), must also be evaluated to not result in reducing core reactivity below the required SDM or refueling boron concentration limit.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3, B.4, B.5.1 and B.5.2

If no RHR loop is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with four bolts;

b. One door in each air lock must be closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Ventilation Isolation System.

With the RHR loop requirements not met, the potential exists for the coolant to boil, clad to fail, and release radioactive gas to the containment atmosphere. Performing the actions described above

BASES

ACTIONS

B.3, B.4, B5.1 and B.5.2 (continued)

ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows adequate time to fulfill the Required Actions and not exceed dose limits.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core.

In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.6.2

Verification that the required pump is OPERABLE ensures that an additional RHR pump can be placed in operation, if needed, to maintain decay heat removal and circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.