Niagara Mohawk

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January 6, 2000
NMP2L 1923

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

RE: Nine Mile Point Unit 2
Docket No. 50-410
NPF-69

Subject: ***Conversion of the Nine Mile Point Unit 2 Current Technical Specifications to the Improved Technical Specifications (TAC No. MA3822)***

Gentlemen:

Niagara Mohawk Power Corporation (NMPC) transmitted an Application for Amendment regarding the above subject by letter dated October 16, 1998 (NMP2L 1830). Subsequently, by letters dated March 26, 1999; May 10, 1999; May 18, 1999; June 16, 1999; September 2, 1999, and September 21, 1999, the Nuclear Regulatory Commission (NRC) requested additional information pertaining to the Application for Amendment. NMPC provided the requested additional information by letters dated May 10, 1999 (NMP2L 1866); June 15, 1999 (NMP2L 1872); July 30, 1999 (NMP2L 1881); August 2, 1999 (NMP2L 1883); August 11, 1999 (NMP2L 1885); August 16, 1999 (NMP2L 1886); August 19, 1999 (NMP2L 1888); August 27, 1999 (NMP2L 1893) and September 10, 1999 (NMP2L 1896). Additionally, meetings were held between the NRC Staff and NMPC on October 20 and 21, 1999 to discuss some of these issues further. The additional information provided by NMPC in these letters and during the meetings and subsequent telephone conversations included commitments to revise the Application for Amendment. Accordingly, the appropriate changes to our Application for Amendment regarding Volumes 1 through 11 of our October 16, 1998 submittal were made via revisions dated September 30, 1999 and December 14, 1999.

The specific revisions included in the enclosure to this letter were made as a result of the recent approval by the Staff of Technical Specification Amendment No. 87 regarding isolation of primary containment bypass leakage paths and/or purge system lines. Additionally, revisions were made to improve clarity as a result of a telephone conference call with the Staff on December 8, 1999, regarding Improved Technical Specification Section 3.3.

A001

Nine Mile Point Nuclear Station P.O. Box 63, Lycoming, New York 13093-0063

Attachment 1 of this letter provides a summary of the changes to the proposed Amendment. In addition, Attachment 2 provides the discard and insertion instructions pertaining to the integration of the proposed changes into our Application for Amendment dated October 16, 1998, as supplemented on September 30, 1999 and December 14, 1999.

NMPC has determined that the revision of our proposed Amendment does not involve a significant hazards consideration. The evaluation supporting this determination is included in the enclosure to our letter dated October 16, 1998, as revised by the September 30, 1999 and December 14, 1999 letters and the enclosure to this letter. In addition, the revision as discussed herein does not create a potential for a significant change in the types or a significant increase in the amounts of any effluents that may be released offsite, nor do the changes involve a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the revision of our proposed Amendment meets the eligibility criteria for categorical exclusion as set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the revision to our proposed Amendment is not required.

Pursuant to 10 CFR 50.91(b)(1), NMPC has provided a copy of the revision to this Amendment application and the associated analysis regarding no significant hazards consideration to the appropriate state representative.

Sincerely,

John H. Mueller
Senior Vice President and
Chief Nuclear Officer

JHM/TWP/kap
Attachments 1 and 2
Enclosure

xc: Mr. H. J. Miller, NRC Regional Administrator, Region I
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ATTACHMENT 1

SUMMARY OF CHANGES

This attachment provides a brief summary of the changes in Revision D. The original Technical Specification (TS) amendment request (Revision A) was submitted to the NRC on October 16, 1998, Revision B was submitted to the NRC on September 30, 1999, and Revision C was submitted to the NRC on December 14, 1999.

The summary of the changes is provided in Chapter/Section order. Within each Chapter/Section, changes resulting from verbal or written communications with the NRC are provided first, followed by additional changes identified by Niagara Mohawk Power Corporation (NMPC). Page removal and insert instructions have also been provided in Attachment 2 to facilitate updating the amendment request to include Revision D.

Chapter 1.0

1. A TS amendment (Amendment No. 87) received subsequent to the original ITS submittal modified the definition of Primary Containment Integrity. However, this does not affect Improved Technical Specifications (ITS) Chapter 1.0 since this definition is not included in the ITS. This change affects the Current Technical Specification (CTS) markup for ITS Chapter 1.0, page 8 of 15.

Section 3.3

1. The changes agreed upon by NMPC during a phone conversation with the NRC reviewer on December 8, 1999 have been made. In addition, during NMPC's subsequent review of the issues discussed in the phone discussion, a typographical error was noted in the Bases. These changes affect ITS 3.3.2.2, Bases page B 3.3-59, ITS 3.3.3.1, Bases page B 3.3-70, ITS 3.3.5.1, Bases pages B 3.3-100, B 3.3-101, B 3.3-102, and B 3.3-119, ITS 3.3.6.1, Bases pages B 3.3-152, B 3.3-153, and B 3.3-164, ITS 3.3.6.2, Bases page B 3.3-196, the Improved Standard Technical Specification (ISTS) Bases markup for ITS 3.3.2.2, insert page B 3.3-52v, the ISTS Bases markup for ITS 3.3.3.1, page B 3.3-61, the ISTS Bases markup for ITS 3.3.5.1, pages B 3.3-93, B 3.3-94, and B 3.3-109, the ISTS Bases markup for ITS 3.3.6.1, pages B 3.3-142 and B 3.3-152, and the ISTS Bases markup for ITS 3.3.6.2, page B 3.3-185.

Section 3.6

1. A TS amendment (Amendment No. 87) received subsequent to the original ITS submittal modified the CTS 3.6.1.2 and 3.6.1.7 actions related to secondary containment bypass leakage rates and purge valve leakage rates not within limits. This change affects ITS 3.6.1.3, pages 3.6-13, 3.6-14, and 3.6-15, and Bases pages B 3.6-21, B 3.6-22, and B 3.6-23, the CTS markup for ITS 3.6.1.1, page 3 of 10, the CTS markup for ITS 3.6.1.3, pages 7 of 14, 10 of 14, and 11 of 14, the Discussion of Changes (DOC) for ITS 3.6.1.3, DOC

A.5 (page 2), DOC A.12 (page 3), DOC M.4 (page 4), DOC L.12 (page 11), DOC L.14 (page 12), and DOC L.17 (page 13), the ISTS markup for ITS 3.6.1.3, page 3.6-11 and insert page 3.6-11, the Justification for Deviations (JFD) to ITS 3.6.1.3, JFD 20 (pages 4 and 5), the ISTS Bases markup pages B 3.6-22 and insert pages B 3.6-22a and B 3.6-22b, and the No Significant Hazards Evaluation (NSHE) for ITS 3.6.1.3, NSHE L.14 (page 16) and NSHE L.17 (page 19).

2. A typographical error was noted and has been corrected. This change affects ITS 3.6.1.7 Bases page B 3.6-48 and ISTS Bases markup insert page B 3.6-47g.

<u>Chapter 5.0</u>

1. A TS amendment (Amendment No. 87) received subsequent to the original ITS submittal modified the CTS 3.6.1.2 actions related to secondary containment bypass leakage rates not within limits. However, this does not affect ITS Chapter 5.0, since the specific CTS change is not part of ITS Chapter 5.0. This change affects the CTS markup for ITS 5.5, page 5 of 22.

ATTACHMENT 2

DISCARD AND INSERTION INSTRUCTIONS

VOLUME 1	
CHAPTER 1.0	
DISCARD	INSERT
CTS markup for Chapter 1.0 page 8 of 15	CTS markup for Chapter 1.0 page 8 of 15
VOLUME 3	
SECTION 3.3: ITS, Bases, and CTS Markup/DOCs	
DISCARD	INSERT
ITS Bases page B 3.3-59	ITS Bases page B 3.3-59
ITS Bases page B 3.3-70	ITS Bases page B 3.3-70
ITS Bases pages B 3.3-100 through B 3.3-102	ITS Bases pages B 3.3-100 through B 3.3-102
ITS Bases page B 3.3-119	ITS Bases page B 3.3-119
ITS Bases pages B 3.3-152 and B 3.3-153	ITS Bases pages B 3.3-152 and B 3.3-153
ITS Bases page 3.3-164	ITS Bases page 3.3-164
ITS Bases page 3.3-196	ITS Bases page 3.3-196
VOLUME 4	
SECTION 3.3: ISTS/JFDs, ISTS Bases/JFDs, and NSHE	
DISCARD	INSERT
ISTS Bases markup insert page B 3.3-52v	ISTS Bases markup insert page B 3.3-52v
ISTS Bases markup page B 3.3-61	ISTS Bases markup page B 3.3-61
ISTS Bases markup pages B 3.3-93 and B 3.3-94	ISTS Bases markup pages B 3.3-93 and B 3.3-94
ISTS Bases markup page B 3.3-109	ISTS Bases markup page B 3.3-109
ISTS Bases markup page B 3.3-142	ISTS Bases markup page B 3.3-142
ISTS Bases markup page B 3.3-152	ISTS Bases markup page B 3.3-152
ISTS Bases markup page B 3.3-185	ISTS Bases markup page B 3.3-185

VOLUME 6	
SECTION 3.6: ITS, Bases, and CTS Markup/DOCs	
DISCARD	INSERT
ITS pages 3.6-13 through 3.6-49	ITS pages 3.6-13 through 3.6-51
ITS Bases pages B 3.6-21 through 3.6-91	ITS Bases pages B 3.6-21 through 3.6-92
CTS markup for Specification 3.6.1.1 page 3 of 10	CTS markup for Specification 3.6.1.1 page 3 of 10
CTS markup for Specification 3.6.1.3 page 7 of 14	CTS markup for Specification 3.6.1.3 page 7 of 14
CTS markup for Specification 3.6.1.3 pages 10 of 14 and 11 of 14	CTS markup for Specification 3.6.1.3 pages 10 of 14 and 11 of 14
Discussion of Changes for ITS 3.6.1.3 pages 2 through 14	Discussion of Changes for ITS 3.6.1.3 pages 2 through 14
VOLUME 7	
SECTION 3.6: ISTS/JFDs, ISTS Bases/JFDs, and NSHE	
DISCARD	INSERT
ISTS markup page 3.6-11	ISTS markup page 3.6-11 and insert page 3.6-11
Justification for Deviations to ITS 3.6.1.3 page 4	Justification for Deviations to ITS 3.6.1.3 pages 4 and 5
ISTS Bases markup page B 3.6-22 and insert page B 3.6-22	ISTS Bases markup page B 3.6-22 and insert pages B 3.6-22a and B 3.6-22b
ISTS Bases markup insert page B 3.6-47g	ISTS Bases markup insert page B 3.6-47g
No Significant Hazards Evaluation for ITS 3.6.1.3 page 16	No Significant Hazards Evaluation for ITS 3.6.1.3 page 16
No Significant Hazards Evaluation for ITS 3.6.1.3 pages 19 through 22	No Significant Hazards Evaluation for ITS 3.6.1.3 pages 19 through 21
VOLUME 11	
SECTION 5.0	
DISCARD	INSERT
CTS markup for Specification 5.5 page 5 of 22	CTS markup for Specification 5.5 page 5 of 22

ENCLOSURE

A.1

Chapter 1.0

PRIMARY CONTAINMENT INTEGRITY

1.31 (Continued)

1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. Each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

A.17

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2, except as provided in Specification 3.6.1.2.

LA.4

e. The suppression pool is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

PROCESS CONTROL PROGRAM

1.32 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formula sampling, analyses, tests, and determinations to be made to ensure that the processing and packaging of radioactive wastes, based on demonstrated processing of actual or simulated wet or liquid wastes, will be accomplished in such a way as to assure compliance with 10 CFR 20, 10 CFR 61, 10 CFR 71, and Federal and State regulations and other requirements governing the transport and disposal of radioactive waste.

A.18 moved to Chapter 5.0

PURGE - PURGING

1.33 PURGE and PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

A.2

RATED THERMAL POWER (RTP)

1.34 ~~RATED THERMAL POWER~~ RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3467 MWt.

A.1

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

1.35 ~~REACTOR PROTECTION SYSTEM~~ The RPS RESPONSE TIME shall be ~~the~~ that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor

A.1

Page 8 of 15

ACTIONS (continued)

C.1 and C.2

With a channel not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the Feedwater System and Main Turbine High Water Level Trip Instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. Alternately, if a channel is inoperable solely due to an inoperable feedwater pump breaker, the affected feedwater pump breaker may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems. 1 D

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the Function maintains feedwater system and main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pumps and main turbine will trip when necessary.

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 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 instrument channels could be an indication of excessive instrument drift in one of the channels, or something even more serious. A CHANNEL CHECK will detect

(continued)

BASES

ACTIONS (continued)

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE 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 PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of actions in accordance with Specification 5.6.6, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This Required Action is appropriate in lieu of a shutdown requirement since another OPERABLE channel is monitoring the Function, an alternate method of monitoring is available, and given the likelihood of plant conditions that would require information provided by this instrumentation. D

C.1

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

(continued)

BASES

BACKGROUND

Low Pressure Core Spray System (continued)

The LPCS pump discharge flow is monitored by a differential pressure transmitter. When the pump is running and discharge flow is low enough that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The differential pressure between the low pressure side of the LPCS injection valve and the reactor vessel is monitored by a differential pressure transmitter. This ensures that, before the injection valve opens, the reactor pressure has fallen to a value below the maximum design pressure of the LPCS System.

Low Pressure Coolant Injection Subsystems

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with three LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High. Reactor vessel water level is monitored by two redundant differential pressure transmitters per division and drywell pressure is monitored by two redundant pressure transmitters per division, each providing input to a trip unit. The outputs of the four Division 2 LPCI (loops B and C) trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Division 1 LPCI (loop A) receives its initiation signal from the LPCS logic, which uses a similar one-out-of-two taken twice logic. The two divisions can also be initiated by use of a manual switch and push button (one per division, with the LPCI A manual switch and push button being common with LPCS), whose two contacts are arranged in a two-out-of-two logic. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

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BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

Upon receipt of an initiation signal, the LPCI Pump C is automatically started in approximately 10 seconds if offsite power is available; otherwise the pump is started in approximately 6 seconds after AC power from the DG is available while LPCI pumps A and B are automatically started in approximately 5 seconds if offsite power is available; otherwise the pumps are started in approximately 1 second after AC power from the DG is available. These time delays limit the loading on the normal and standby power sources.

Each LPCI subsystems discharge flow is monitored by a differential pressure transmitter. When a pump is running and discharge flow is low enough that pump overheating may occur, the respective minimum flow return line valve is opened after approximately 8 seconds. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the analyses. D

The RHR spray isolation valves (which are also PCIVs) and suppression pool cooling full flow test valves are closed on a LPCI initiation signal to allow full system flow assumed in the accident analysis and, in the case of the spray isolation valves, to maintain the containment isolated in the event LPCI is not operating.

The RHR A and B heat exchanger sample and RHR B discharge to radwaste valves (Group 4 valves) are closed on either a Reactor Vessel Water Level—Low, Level 3 signal or a Drywell Pressure—High signal to allow full system flow assumed in the accident analysis. (The RHR A discharge to radwaste valves are manual valves; they do not receive an automatic signal.) These valves can also be closed using the remote manual control switches. Reactor vessel water level is monitored by two differential pressure transmitters per division and drywell pressure is monitored by two pressure transmitters per division, each providing input to a trip unit. The outputs of these channels for each Function are arranged into a two-out-of-two trip system for each division. The LPCI A (Division 1) trip systems close the outboard valves while the LPCI B (Division 2) trip systems close the inboard valves. However, since only one of the valves in each line must be closed to preclude flow diversion, and the valves must be capable of closing when

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BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

the associated LPCI receives an initiation signal, only the valves receiving power and logic from their associated division must be capable of closing. Thus, the LPCI A trip systems must close the outboard RHR A heat exchanger sample valve and LPCI B trip systems must close the inboard RHR B heat exchanger sample valve and the inboard RHR B discharge to radwaste valve.

The differential pressure between the low pressure side of the LPCI injection valves and the reactor vessel is monitored by a differential pressure transmitter. This ensures that, prior to an injection valve opening, the reactor pressure has fallen to a value below the maximum design pressure of the LPCI subsystem.

High Pressure Core Spray System

The HPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High. Reactor vessel water level is monitored by four redundant differential pressure transmitters and drywell pressure is monitored by four redundant pressure transmitters, each providing input to a trip unit. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each variable. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two-logic. The HPCS System initiation signal is a sealed in signal and must be manually reset.

The HPCS pump discharge flow and pressure are monitored by a differential pressure and pressure transmitter, respectively. Each transmitter is connected to a trip unit. When the pump is running (as indicated by the pressure transmitter) and discharge flow is low enough that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow full system flow assumed in the accident analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.g, 3.h. HPCS Pump Discharge Pressure—High (Bypass) and HPCS System Flow Rate—Low (Bypass) (continued)

analyzed in References 1, 2, and 3 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One differential pressure transmitter is used to detect the HPCS System's flow rate. The logic is arranged such that the transmitter causes the minimum flow valve to open, provided the HPCS pump discharge pressure, sensed by another transmitter, is high enough (indicating the pump is operating). The logic will close the minimum flow valve once the closure setpoint is exceeded. (The valve will also close upon HPCS pump discharge pressure decreasing below the setpoint.)

The HPCS System Flow Rate—Low (Bypass) Allowable Values are high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The HPCS Pump Discharge Pressure—High (Bypass) Allowable Value is set high enough to ensure that the valve will not be open when the pump is not operating.

One channel of each Function is required to be OPERABLE when the HPCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.i. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the HPCS logic to provide manual initiation capability and is redundant to the automatic protective instrumentation. There is one switch and push button (with two channels) for the HPCS System. D

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

(continued)

BASES

BACKGROUND (continued)

1. Main Steam Line Isolation

Most Main Steam Line Isolation Functions receive inputs from four channels. The outputs from these channels are combined in one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two trip systems to isolate all MSL drain valves. One two-out-of-two trip system is associated with the inboard valve and the other two-out-of-two trip system is associated with the outboard valves.

The exceptions to this arrangement are the Main Steam Line Flow—High, Main Steam Line Tunnel Lead Enclosure Temperature—High, and the Manual Initiation Functions. The Main Steam Line Flow—High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of four trip strings. Two trip strings make up each trip system, and both trip systems must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two logic. Therefore, this is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two trip systems (effectively, two one-out-of-four taken twice logic), with one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Main Steam Line Tunnel Lead Enclosure Temperature—High Function uses 12 temperature channels, three for each trip string. One sensor in each trip string is measuring the temperature in one of the three areas of the lead enclosure. Two trip strings make up each trip system, and both trip systems must trip to cause a MSL isolation. One sensor is required to trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two logic. Therefore, this is effectively a one-out-of-two taken twice logic arrangement for each enclosure area to initiate isolation of the MSIVs. The 12 temperature channels are connected into two two-out-of-two trip systems for each enclosure area, with one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Manual Initiation Function uses eight channels, two per switch and push button. The four channels from two | D

(continued)

BASES

BACKGROUND

1. Main Steam Line Isolation (continued)

switch and push buttons input into one trip system and the four channels from the other two switch and push buttons input into the other trip system. To close all MSIVs, both trip systems must actuate, similar to all the other Functions described above. However, the logic of each trip system is arranged such that both channels from one of the associated switch and push buttons are required to actuate the trip system (i.e., the switch and push button must be both armed and depressed for the trip system to actuate). To close the MSL drain valves, all channels in both trip systems must actuate (i.e., both channels from each of the two associated switch and push buttons are required to actuate the inboard valve trip system and both channels from each of the two associated switch and push buttons are required to actuate the outboard valve trip system). | D

MSL Isolation Functions isolate the Group 1 valves.

2. Primary Containment Isolation

Most Primary Containment Isolation Functions receive inputs from four channels. The outputs from these channels are arranged into two two-out-of-two trip systems. The two exceptions to this logic arrangement are the SGT System Exhaust Radiation—High and the Manual Initiation Functions. The SGT System Exhaust Radiation—High Function uses two channels, with one channel in each trip system arranged in a one-out-of-one logic. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. In general, one trip system initiates isolation of all inboard PCIVs, while the other trip system initiates isolation of all outboard PCIVs. Each trip system closes one of the two valves on each penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement, which have been previously approved by the NRC as part of the issuance of the Operating License, are described in USAR Table 6.2-56 (Ref. 1). In addition, the withdrawal of the traversing in-core probes using the drive mechanisms is part of the Group 3 isolation valve function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.b. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB inside the drywell. The isolation of some of the PCIVs on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure—High Function associated with isolation of the primary containment is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the RPS Drywell Pressure—High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 3, 8, and 9 valves.

2.c. Standby Gas Treatment (SGT) System Exhaust Radiation—High

High ventilation exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When Exhaust Radiation—High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products.

The Exhaust Radiation—High signals are initiated from a radiation detector that is located on the ventilation exhaust piping of the SGT System. The signal from the detector is input to an individual monitor whose trip output, after a preselected time delay, is assigned to both isolation channels. Two channels of SGT Exhaust—High Function are available and are required to be OPERABLE to ensure that no single instrument failure, other than the sensor/trip output, can preclude the isolation function. D

(continued)

BASES

ACTIONS

B.1 (continued)

isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For the Functions with two two-out-of-two trip systems (Functions 1 and 2), this would require one trip system to have two channels, each OPERABLE or in trip. For the Functions with two one-out-of-one trip systems (Functions 3 and 4), this would require one trip system to have one channel OPERABLE or in trip.

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

C.1.1, C.1.2, C.2.1, and C.2.2

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the associated penetration flow path(s) and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operations to continue. The method used to place the SGT subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the SGT subsystem. D

Alternatively, declaring the associated SCIVs or SGT subsystem inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components.

(continued)

1 Insert BWR/4 ISTS B 3.3.2.2
(continued)

BASES

ACTIONS (continued) 2

C.1 and C.2 2

Alternately, if a channel is inoperable solely due to an inoperable feedwater pump breaker, the affected feedwater pump breaker may be removed from service since this performs the intended function of the instrumentation.

With ~~the required~~ channel(s) not restored to OPERABLE status 5 or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater System 2 and main turbine high water level trip instrumentation is 4 not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

1D

SURVEILLANCE REQUIREMENTS

~~Reviewer's Note: Certain Frequencies are based on approved topical reports. In order for a licensee to use these Frequencies the licensee must justify the Frequencies as required by the staff Safety Evaluation Report (SER) for the topical report.~~ 6

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains feedwater System 2 and main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) 4 3 assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pump 5 3 turbines and main turbine will trip when necessary.

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter

(continued)

Insert Page B 3.3-52v

BASES

ACTIONS

B.1 (continued)

requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This Required Action is appropriate in lieu of a shutdown requirement since another OPERABLE channel is monitoring the Function, or alternate method of monitoring is available ~~alternative Actions are identified before loss of functional capability,~~ and given the likelihood of plant conditions that would require information provided by this instrumentation.

3

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur. ~~Condition C is modified by a Note that excludes hydrogen monitor channels. Condition D provides appropriate Required Actions for two inoperable hydrogen monitor channels.~~ 2

D

~~D.1~~

~~When two hydrogen monitor channels are inoperable, one hydrogen monitor channel must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable, based on the backup capability of the Post Accident Sampling System to monitor the hydrogen concentration for evaluation of core damage and to provide information for operator decisions. Also, it is unlikely that a LOCA that would cause core damage would occur during this time.~~ 2

(continued)

All changes are (2) unless otherwise indicated

BASES

BACKGROUND Low Pressure Core Spray System (continued)

low enough that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

1

differential

The ~~LPCS System also monitors the~~ pressure ~~in~~ the reactor vessel, ~~to~~ ensures that, before the injection valve opens, the reactor pressure has fallen to a value below the LPCS System's maximum design pressure. ~~The variable is monitored by four redundant transmitters, which are, in turn, connected to trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic.~~

between the low pressure side of the LPCS injection valve and

of the

1

D

is monitored by a differential pressure transmitter. This

1

Low Pressure Coolant Injection Subsystems

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with three LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High. ~~Each of these diverse variables~~ is monitored by two redundant transmitters per Division, ~~which are, in turn, connected to two~~ trip units. The outputs of the four Division 2 LPCI (loops B and C) trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Division 1 LPCI (loop A) receives its initiation signal from the LPCS logic, which uses a similar one-out-of-two taken twice logic. The two Divisions can also be initiated by use of a manual push button (one per Division). Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

Reactor vessel water level is monitored by two redundant differential pressure transmitters per division and drywell pressure

pressure

each providing input to a

1

switch and

, with the LPCI A manual switch and push button being common with LPCS

, whose two contacts are arranged in a two-out-of-two logic

1

in approximately 5 seconds

AC

from the DG

Upon receipt of an initiation signal, the LPCI Pump C is started ~~immediately~~ after power is available while LPCI A and ~~LPCI~~ B pumps are started ~~after a 5 second delay, to~~ limit the loading on the standby power sources.

in approximately 1 second after AC power from the DG is available. These time delays

normal and

is automatically started in approximately 10 seconds if offsite power is available; otherwise the pump

are automatically started in approximately 5 seconds if offsite power is available; otherwise the pumps

Each LPCI subsystem's discharge flow is monitored by a ~~flow~~ transmitter. When a pump is running and discharge flow is low enough that pump overheating may occur, the respective

differential pressure

3

(continued)

All changes are 2 unless otherwise indicated

BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

minimum flow return line valve is opened after approximately 8 seconds. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the analyses.

The RHR test line and suppression pool cooling isolation and suppression pool spray isolation valves (which are also PCIVs) full flow test valves are closed on a LPCI initiation signal to allow full system flow assumed in the accident analysis and maintain containment isolated in the event LPCI is not operating. in the case of the spray isolation valves

The LPCI subsystems monitor the differential pressure in the reactor vessel to ensure that, prior to an injection valve opening, the reactor pressure has fallen to a value below the LPCI subsystem's maximum design pressure. The variable is monitored by four redundant transmitters per Division, which are, in turn, connected to four trip units. The outputs of the four Division 2 LPCI (loops B and C) trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Division 1 LPCI (loop A) receives its signal from the LPCS logic, which uses a similar one-out-of-two taken twice logic.

INSERT LPCI

the

between the low pressure side of the LPCI injection valves and

of the

is monitored by a differential pressure transmitter. This

1

D

High Pressure Core Spray System

The HPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each variable. The HPCS System initiation signal is a sealed in signal and must be manually reset.

Reactor vessel water level is monitored by four redundant differential pressure transmitters and drywell pressure is monitored by four redundant pressure transmitters, each providing input to a trip unit.

The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic

differential pressure

and pressure

Each transmitter is connected to a trip unit.

The HPCS pump discharge flow and pressure is are monitored by a flow transmitter respectively. When the pump is running and discharge flow is low enough that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow full system flow assumed in the accident analyses.

(as indicated by the pressure transmitter)

The HPCS full flow test line isolation valve to the suppression pool (which is also a PCIV) is closed on a HPCS initiation signal to allow full system flow

and the full flow test line isolation valves to the CST are

(continued)

BASES

5 g h

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.f. 3.g. HPCS Pump Discharge Pressure—High (Bypass) and HPCS System Flow Rate—Low (Bypass) (continued)

during the transients and accidents analyzed in References 1, 2, and 3 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

2 differential pressure

One ~~flow~~ transmitter is used to detect the HPCS System's flow rate. The logic is arranged such that the transmitter causes the minimum flow valve to open, provided the HPCS pump discharge pressure, sensed by another transmitter, is high enough (indicating the pump is operating). The logic will close the minimum flow valve once the closure setpoint is exceeded. (The valve will also close upon HPCS pump discharge pressure decreasing below the setpoint.)

2 (Bypass) 6 5

The HPCS System Flow Rate—Low ~~and HPCS Pump Discharge Pressure—High~~ Allowable Value ~~is~~ are 6 high enough to ensure that ~~pump flow rate is sufficient~~ to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The HPCS Pump Discharge Pressure—High Allowable Value is set high enough to ensure ~~that the~~ valve will not be open when the pump is not operating.

One channel of each Function is required to be OPERABLE when the HPCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

5 i

3.h. Manual Initiation

switch and 2 3 1 D

The Manual Initiation push button channel introduces a signal into the HPCS logic to provide manual initiation capability and is redundant to the automatic protective instrumentation. There is one push button for the HPCS System. (with two channels)

2 e 1 2

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

(continued)

BASES All changes are 1 unless otherwise indicated

BACKGROUND (continued)

1. Main Steam Line Isolation

Most Main Steam Line Isolation Functions receive inputs from four channels. The outputs from these channels are combined in one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two logic trip systems to isolate all MSL drain valves. ~~Each MSL drain line has two isolation valves with~~ one two-out-of-two logic system associated with each valve. trip is the inboard and the other two-out-of-two trip system is associated with the outboard valves.

The exception to this arrangement is the Main Steam Line Flow—High Function. This Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of four trip strings. Two trip strings make up each trip system, and both trip systems must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two taken twice logic. Therefore, this is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two logic trip systems (effectively, two one-out-of-four twice logic), with each trip system isolating one of the two MSL drain valves.

s are , Main Steam Line Tunnel Lead Enclosure Temperature—High, and the Manual Initiation The Main Steam Line Flow—High Function 1D taken INSERT BKGRD 1 one inboard and the other trip system isolating the outboard MSL drain valves.

2. Primary Containment Isolation

Each Primary Containment Isolation Function receives inputs from four channels. The outputs from these channels are arranged into two two-out-of-two logic trip systems. One trip system initiates isolation of all inboard PCIVs, while the other trip system initiates isolation of all outboard PCIVs. Each trip system logic closes one of the two valves on each penetration so that operation of either trip system isolates the penetration. Insert BKGRD 2B

Most s Insert BKGRD 2A

3. Reactor Core Isolation Cooling System Isolation

Most Functions receive input from two channels, with each channel in one trip system using one-out-of-one logic. Functions 3.g and 3.h (RHR Equipment Room Temperature) have one channel in each trip system in each room for a total of four channels per Function; but the logic is the same

h, i, 3.g, Area, , eight, and ten, , respectively, /area

(continued)

—High, Reactor Building Pipe Chase Area Temperature—High, and Reactor Building General Area Temperature—High functions

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value (LCO 3.3.5.1) to ensure the valves are isolated to prevent offsite doses from exceeding 10 CFR 100 limits.

This Function isolates the E61 isolation valves.

4 C

2.d. ~~Containment and Drywell Ventilation~~ Exhaust Radiation—High Standby Gas Treatment (SGT) System 1

High ventilation exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When Exhaust Radiation—High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products. Additionally, the Ventilation Exhaust Radiation—High is assumed to initiate isolation of the primary containment during a fuel handling accident (Ref. 2). 1

The Exhaust Radiation—High signals are initiated from radiation detectors that ~~are~~ is located on the ventilation exhaust piping ~~coming from the drywell and containment~~ of the SGT System. The signal from ~~each~~ the detector is input to an individual monitor whose trip outputs ~~are~~, after a preselected time delay, is assigned to ~~an~~ both isolation channel. 5 ~~Four~~ Two channels of ~~Containment and Drywell Ventilation~~ SGT Exhaust—High Function are available and are required to be OPERABLE to ensure that no single instrument failure, other than the sensor trip output, can preclude the isolation function. 1 4 a

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding and to ensure offsite doses remain below 10 CFR 20 and 10 CFR 100 limits.

The Function is required to be OPERABLE during CORE ALTERATIONS, operations with a potential for draining the reactor vessel (OPDRVs), and movement of irradiated fuel assemblies in the primary or secondary containment because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) 4 1 D

(continued)

BASES

ACTIONS (continued)

C.1.1, C.1.2, C.2.1, and C.2.2

3

associated penetration flow path(s)

10

1

The method used to place the SGT subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the SGT subsystem.

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the ~~associated valves~~ and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operations to continue.

Alternatively, declaring the associated SCIVs or SGT subsystem inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components.

One hour is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without challenging plant systems.

SURVEILLANCE REQUIREMENTS

5

~~Reviewer's Note: Certain Frequencies are based on approved topical reports. In order for a licensee to use these Frequencies, the licensee must justify the Frequencies as required by the staff SER for the topical report.~~

As noted at the beginning of the SRs, the SRs for each Secondary Containment Isolation instrumentation Function are located in the SRs column of Table 3.3.6.2-1.

3

The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains ~~secondary containment~~ isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Action(s) taken.

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more penetration flowpaths with secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested line leakage rate not within limit.	D.1 ---------NOTE--------- The isolation device used to satisfy Required Action D.1 shall have been verified to meet the applicable leakage rate limit of the inoperable valve. ---------------------	
	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours for hydrostatically tested line leakage not on a closed system AND 4 hours for secondary containment bypass leakage AND 8 hours for MSIV leakage AND 72 hours for hydrostatically tested line leakage on a closed system
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.2 ---------NOTES-------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. --------------------- Verify the affected penetration flow path is isolated.	 Once per 31 days for isolation devices outside primary containment <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment
	<u>AND</u>	(continued)

P

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. (continued)	D.3	Perform SR 3.6.1.3.6 for the resilient seal purge supply valves closed to comply with Required Action D.1.	Once per 92 days
E. One or more penetration flow paths with one or more containment purge exhaust valves not within purge valve leakage limits.	E.1 AND	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	24 hours (continued)

D

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. (continued)	E.2	---------NOTES-------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------------------	
		Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside containment
	<u>AND</u>		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. (continued)	E.3	Perform SR 3.6.1.3.6 for the resilient seal purge exhaust valves closed to comply with Required Action E.1.	Once per 92 days
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met in MODE 1, 2, or 3.	F.1	Be in MODE 3.	12 hours
	AND		
	F.2	Be in MODE 4.	36 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, or E not met for PCIV(s) required to be OPERABLE during MODE 4 or 5.	G.1	Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRV)s.	Immediately
	OR		
	G.2	Initiate action to restore valve(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.1	-------------------NOTE------------------- Not required to be met when the 12 inch and 14 inch primary containment purge valves are open for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open, provided: a) the Standby Gas Treatment (SGT) System is OPERABLE; or b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE. -- Verify each 12 inch and 14 inch primary containment purge valve is closed.	31 days
SR 3.6.1.3.2	-------------------NOTES------------------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for PCIVs that are open under administrative controls. -- Verify each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.3	------------------NOTES------------------ 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for PCIVs that are open under administrative controls. -- Verify each primary containment isolation manual valve and blind flange that is located inside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	Prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days
SR 3.6.1.3.4	Verify continuity of the traversing incore probe (TIP) shear isolation valve explosive charge.	31 days
SR 3.6.1.3.5	Verify the isolation time of each power operated, automatic PCIV, except MSIVs, is within limits.	In accordance with the Inservice Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.6	Perform leakage rate testing for each primary containment purge valve with resilient seals.	184 days AND Once within 92 days after opening the valve
SR 3.6.1.3.7	Verify the isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.6.1.3.8	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	24 months
SR 3.6.1.3.9	Verify each EFCV actuates to the isolation position on an actual or simulated instrument line break signal.	24 months
SR 3.6.1.3.10	Remove and test the explosive squib from each shear isolation valve of the TIP System.	24 months on a STAGGERED TEST BASIS
SR 3.6.1.3.11	Verify the leakage rate for the secondary containment bypass leakage paths is within the limits of Table 3.6.1.3-1 when pressurized to ≥ 40 psig.	In accordance with 10 CFR 50 Appendix J Testing Program Plan

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.12	Verify leakage rate through each MSIV is ≤ 24 scfh when tested at ≥ 40 psig.	In accordance with 10 CFR 50 Appendix J Testing Program Plan
SR 3.6.1.3.13	Verify combined leakage rate through hydrostatically tested lines that penetrate the primary containment is within limits.	In accordance with 10 CFR 50 Appendix J Testing Program Plan

Table 3.6.1.3-1 (page 1 of 2)
Secondary Containment Bypass Leakage Paths Leakage Rate Limits

VALVE NUMBER	PER VALVE LEAK RATE (SCFH)
2MSS*MOV111 2MSS*MOV112	1.875
2MSS*MOV208	0.625
2CMS*SOV74A, B 2CMS*SOV75A, B 2CMS*SOV76A, B 2CMS*SOV77A, B	0.2344
2DER*MOV119 2DER*MOV120	1.25
2DER*MOV130 2DER*MOV131	0.625
2DFR*MOV120 2DFR*MOV121	1.875
2DFR*MOV139 2DFR*MOV140	0.9375
2WCS*MOV102 2WCS*MOV112	2.5
2FWS*AOV23A, B 2FWS*V12A, B	12.0
2CPS*AOV104 2CPS*AOV106	4.38
2CPS*AOV105 2CPS*AOV107	3.75

(continued)

Table 3.6.1.3-1 (page 2 of 2)
Secondary Containment Bypass Leakage Paths Leakage Rate Limits

VALVE NUMBER	PER VALVE LEAK RATE (SCFH)
2CPS*SOV119 2CPS*SOV120 2CPS*SOV121 2CPS*SOV122	0.625
2IAS*SOV164 2IAS*V448	0.9375
2IAS*SOV165 2IAS*V449	0.9375
2GSN*SOV166 2GSN*V170	(a)
2IAS*SOV166 2IAS*SOV184	(a)
2IAS*SOV167 2IAS*SOV185	(a)
2IAS*SOV168 2IAS*SOV180	(a)
2CPS*SOV132 2CPS*V50	(a)
2CPS*SOV133 2CPS*V51	(a)

(a) The combined leak rate for these penetrations shall be ≤ 3.6 SCFH. The assigned leakage rate through a penetration shall be that of the valve with the highest leakage rate in that penetration. However, if a penetration is isolated by one closed and de-activated automatic valve, closed manual valve, or blind flange, the leakage through the penetration shall be the actual pathway leakage.

3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell and Suppression Chamber Pressure

LCO 3.6.1.4 Drywell and suppression chamber pressure shall be ≥ 14.2 psia and ≤ 15.45 psia.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Drywell or suppression chamber pressure not within limits.	A.1	Restore drywell and suppression chamber pressure to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.4.1	Verify drywell and suppression chamber pressure is within limits.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.5 Drywell Air Temperature

LCO 3.6.1.5 Drywell average air temperature shall be ≤ 150°F.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1 Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.5.1	Verify drywell average air temperature is within limit.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Residual Heat Removal (RHR) Drywell Spray System

LCO 3.6.1.6 Two RHR drywell spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR drywell spray subsystem inoperable.	A.1	Restore RHR drywell spray subsystem to OPERABLE status.	7 days
B. Two RHR drywell spray subsystems inoperable.	B.1	Restore one RHR drywell spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	C.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	Verify each RHR drywell spray subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.1.6.2	Verify, by administrative means, that each required RHR pump is OPERABLE.	92 days
SR 3.6.1.6.3	Verify each drywell spray nozzle is unobstructed.	10 years

C

C

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.7 Each suppression chamber-to-drywell vacuum breaker shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One line with one or more suppression chamber-to-drywell vacuum breakers inoperable for opening.	A.1	Restore the vacuum breaker(s) to OPERABLE status.	72 hours
B. ---------NOTE--------- Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker line. ---------------------- One or more lines with one suppression chamber-to-drywell vacuum breaker not closed.	B.1	Close the open vacuum breaker.	72 hours

(continued)

B

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE---------- Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker line. ---------------------- One or more lines with two suppression chamber-to-drywell vacuum breakers disks not closed.	C.1	Close one open vacuum breaker.	2 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	D.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.1	------------------NOTES------------------ 1. Not required to be met for vacuum breakers that are open during Surveillances. 2. Not required to be met for vacuum breakers open when performing their intended function. --------------------------------------- Verify each vacuum breaker is closed.	14 days
SR 3.6.1.7.2	Perform a functional test of each vacuum breaker.	31 days AND Within 12 hours after any discharge of steam to the suppression chamber from the safety/relief valves
SR 3.6.1.7.3	Verify the opening setpoint of each vacuum breaker is ≤ 0.25 psid.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.2.1 Suppression Pool Average Temperature

LCO 3.6.2.1 Suppression pool average temperature shall be:

a. ≤ 90°F with THERMAL POWER > 1% RTP and no testing that adds heat to the suppression pool is being performed;

b. ≤ 105°F with THERMAL POWER > 1% RTP and testing that adds heat to the suppression pool is being performed; and

c. ≤ 110°F with THERMAL POWER ≤ 1% RTP.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool average temperature > 90°F but ≤ 110°F. <u>AND</u> THERMAL POWER > 1% RTP. <u>AND</u> Not performing testing that adds heat to the suppression pool.	A.1 Verify suppression pool average temperature ≤ 110°F. <u>AND</u> A.2 Restore suppression pool average temperature to ≤ 90°F.	Once per hour 24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to ≤ 1% RTP.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Suppression pool average temperature > 105°F. AND THERMAL POWER > 1% RTP. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F but ≤ 120°F.	D.1 Place the reactor mode switch in the shutdown position.	Immediately
	AND	
	D.2 Verify suppression pool average temperature ≤ 120°F.	Once per 30 minutes
	AND	
	D.3 Be in MODE 4.	36 hours
E. Suppression pool average temperature > 120°F.	E.1 Depressurize the reactor vessel to < 200 psig.	12 hours
	AND	
	E.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1.1	Verify suppression pool average temperature is within the applicable limits.	24 hours AND 5 minutes when performing testing that adds heat to the suppression pool

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 199 ft 6 inches and ≤ 201 ft

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Suppression pool water level not within limits.	A.1	Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.2.1	Verify suppression pool water level is within limits.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1	Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days
B. Two RHR suppression pool cooling subsystems inoperable.	B.1	Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	C.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify each RHR suppression pool cooling subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.2.3.2	Verify each required RHR pump develops a flow rate $\geq$ 7450 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

LCO 3.6.2.4 Two RHR suppression pool spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1 Restore RHR suppression pool spray subsystem to OPERABLE status.	7 days
B. Two RHR suppression pool spray subsystems inoperable.	B.1 Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.4.1	Verify each RHR suppression pool spray subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.2.4.2	Verify each required RHR pump develops a flow rate $\geq$ 450 gpm while operating in the suppression pool spray mode.	In accordance with the Inservice Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.3.1 Primary Containment Hydrogen Recombiners

LCO 3.6.3.1 Two primary containment hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One primary containment hydrogen recombiner inoperable.	A.1	---------NOTE--------- LCO 3.0.4 is not applicable. --------------------- Restore primary containment hydrogen recombiner to OPERABLE status.	30 days
B. Two primary containment hydrogen recombiners inoperable.	B.1	Verify by administrative means that the hydrogen and oxygen control function is maintained.	1 hour AND Once per 12 hours thereafter
	AND		
	B.2	Restore one primary containment hydrogen recombiner to OPERABLE status.	7 days

(continued)

B

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Perform a system functional test for each primary containment hydrogen recombiner.	24 months
SR 3.6.3.1.2	Perform a resistance to ground test for each heater phase.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.3.2 Primary Containment Oxygen Concentration

LCO 3.6.3.2 The primary containment oxygen concentration shall be < 4.0 volume percent.

APPLICABILITY: MODE 1 during the time period:

a. From 24 hours after THERMAL POWER is > 15% RTP following startup, to

b. 24 hours prior to reducing THERMAL POWER to < 15% RTP prior to the next scheduled reactor shutdown.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Primary containment oxygen concentration not within limit.	A.1 Restore oxygen concentration to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to $\leq$ 15% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.3.2.1 Verify primary containment oxygen concentration is within limits.	7 days

3.6 CONTAINMENT SYSTEMS

3.6.4.1 Secondary Containment

LCO 3.6.4.1 The secondary containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Secondary containment inoperable in MODE 1, 2, or 3.	A.1 Restore secondary containment to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Secondary containment inoperable during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	C.1	---------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately
	<u>AND</u>		
	C.2	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	C.3	Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify secondary containment vacuum is $\geq$ 0.25 inch of vacuum water gauge.	24 hours
SR 3.6.4.1.2	Verify all secondary containment equipment hatches are closed and sealed.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.3	Verify one secondary containment access door in each access opening is closed.	31 days
SR 3.6.4.1.4	Verify the secondary containment can be drawn down to ≥ 0.25 inch of vacuum water gauge in ≤ 66.7 seconds using one standby gas treatment (SGT) subsystem.	24 months on a STAGGERED TEST BASIS for each SGT subsystem
SR 3.6.4.1.5	Verify the secondary containment can be maintained ≥ 0.25 inch of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm.	24 months on a STAGGERED TEST BASIS for each SGT subsystem

3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

LCO 3.6.4.2 Each SCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIVs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more penetration flow paths with one SCIV inoperable.	A.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	8 hours
	<u>AND</u>		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	---------NOTE--------- Isolation devices in high radiation areas may be verified by use of administrative means. --------------------- Verify the affected penetration flow path is isolated.	 Once per 31 days
B. ----------NOTE---------- Only applicable to penetration flow paths with two isolation valves. ---------------------- One or more penetration flow paths with two SCIVs inoperable.	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 AND C.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	D.1	---------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately
	AND		
	D.2	Suspend CORE ALTERATIONS.	Immediately
	AND		
	D.3	Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.4.2.1	-------------------NOTES------------------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for SCIVs that are open under administrative controls. --- Verify each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	31 days
SR 3.6.4.2.2	Verify the isolation time of each power operated, automatic SCIV is within limits.	92 days
SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated automatic isolation signal.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.4.3 Standby Gas Treatment (SGT) System

LCO 3.6.4.3 Two SGT subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SGT subsystem inoperable.	A.1 Restore SGT subsystem to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, or 3.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours
C. Required Action and associated Completion Time of Condition A not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	------------NOTE------------ LCO 3.0.3 is not applicable. ---------------------------- C.1 Place OPERABLE SGT subsystem in operation. OR	Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1 Suspend movement of irradiated fuel assemblies in the secondary containment. AND C.2.2 Suspend CORE ALTERATIONS. AND C.2.3 Initiate action to suspend OPDRVs.	Immediately Immediately Immediately
D. Two SGT subsystems inoperable in MODE 1, 2, or 3.	D.1 Enter LCO 3.0.3.	Immediately
E. Two SGT subsystems inoperable during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	E.1 --------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Suspend movement of irradiated fuel assemblies in the secondary containment. AND	 Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. (continued)	E.2 Suspend CORE ALTERATIONS. AND E.3 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.3.1	Operate each SGT subsystem for ≥ 10 continuous hours with heaters operating.	31 days
SR 3.6.4.3.2	Perform required SGT filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.3.3	Verify each SGT subsystem actuates on an actual or simulated initiation signal.	24 months
SR 3.6.4.3.4	Verify each SGT decay heat removal air inlet valve can be opened.	24 months

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note indicating this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two or more PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified 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, once they have been verified to be in the proper position, is low.

D.1, D.2, and D.3

With the secondary containment bypass leakage rate (SR 3.6.1.3.11), MSIV leakage rate (SR 3.6.1.3.12), or hydrostatically tested line leakage rate (SR 3.6.1.3.13) not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage rate must be restored to within limit or the affected penetration flow path must be isolated within the Completion Times appropriate for each type of valve leakage: a) hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage are required to be restored within 4 hours; b) MSIV leakage is required to be restored within 8 hours; and c) hydrostatically tested line leakage on a closed system is required to be restored within 72 hours. 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 automatic valve, a closed manual valve, and a blind flange. Required

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

Action D.1 is modified by a Note stating that the isolation device used to satisfy the Required Action must meet the same leakage rate requirements as the inoperable valve. Thus, when the 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 for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of secondary containment bypass leakage to the overall containment function. The Completion Time of 8 hours for MSIV leakage allows a period of time to restore the MSIV leakage and is acceptable given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is acceptable based on the available water seal expected to remain as a gaseous fission product boundary during the accident and, in many cases, the associated closed system. The closed system must meet the requirements of Ref. 6.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no 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 valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, 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.

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified 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 once they have been verified to be in the proper position, is low.

For the containment purge supply valve with resilient seal that is closed in accordance with Required Action D.1, SR 3.6.1.3.6 must be performed at least once every 92 days, as required by D.3. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge supply valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

E.1, E.2, and E.3

In the event one or more containment purge exhaust valves are not within the purge valve leakage limits, purge exhaust valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by 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 automatic valve, closed manual valve, and blind flange. If a purge exhaust valve with resilient seals is utilized to satisfy Required Action E.1 it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.6. The specified Completion Time

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no 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 valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, 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.

Required Action E.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified 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 once they have been verified to be in the proper position, is low. B B

For the containment purge exhaust valve with resilient seal that is closed in accordance with Required Action E.1, SR 3.6.1.3.6 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

containment purge exhaust valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

F.1 and F.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, 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 12 hours and to MODE 4 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.

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required OPERABLE in MODE 4 or 5, the plant must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. If suspending the OPDRVs would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valves to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR verifies that the 12 inch and 14 inch primary containment purge valves are closed as required or, if open, opened for an allowable reason.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

The SR is modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA, or air quality considerations for personnel entry, or for Surveillances that require the valves to be open, provided that either: a) the SGT System is OPERABLE (i.e., both subsystems); or b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE. These primary containment purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The allowance is intended to balance the operational needs of the unit with the requirement to preclude a radiological release through the purge exhaust lines. With the primary containment atmosphere being exhausted through the containment full flow line to the SGT System, a pressure transient could damage the operating SGT subsystem. Thus both subsystems are required to be OPERABLE when the full flow line is in service. This ensures that, if an accident occurs that damages the operating SGT subsystem, the remaining SGT subsystem is still available to perform the intended SGT System safety function. When the full flow line is not in service (i.e., the two inch bypass valve is open), then only one SGT subsystem is required to be OPERABLE since a pressure transient cannot damage the operating SGT subsystem. The 31 day Frequency is consistent with other primary containment isolation valve requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of position for PCIVs outside primary containment is relatively easy, the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.2 (continued)

31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions. 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.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days," is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. | B

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.6.1.3.5

Verifying the isolation time of each power operated, automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.7. The isolation time test ensures that each valve will isolate in a time period less than or equal to that assumed in the safety analysis. The Frequency of this SR is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J Option B (Ref. 7), is required to ensure OPERABILITY. The primary containment purge supply valves, which are secondary containment bypass leakage pathway valves, are tested at a pressure of 40.0 psig and the primary containment purge exhaust valves, which are not secondary containment bypass leakage pathway valves, are tested at P_a, 39.75 psig. The leakage limit for the 12 inch supply and exhaust valves are 3.75 scfh while the 14 inch supply and exhaust valve leakage limit is 4.38 scfh. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining these penetrations leak tight (due to the direct path between primary containment and the environment in some cases), a Frequency of 184 days was established. Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.3.8

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.8 (continued)

Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. 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 at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. In addition, this Surveillance shall be performed in MODE 4 or 5.

SR 3.6.1.3.9

This SR requires a demonstration that each EFCV is OPERABLE by verifying that the valve actuates to the isolation position on an actual or simulated instrument line break condition. This SR provides assurance that the instrumentation line EFCVs will perform as designed. Some hydraulic EFCVs are tested by providing an instrument line break signal with reactor pressure above 600 psig. Testing above this pressure range provides a high degree of assurance that these valves will close during an instrument line break while at normal operating pressure. The remaining hydraulic EFCVs are tested with process fluid or demin water at low pressure. The pneumatic EFCVs are tested by providing an instrument line break signal with pressure at approximately 15 psig to 150 psig. These test pressures are selected to simulate the actual operating conditions the EFCVs are expected to experience during instrument line breaks outside containment.

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 at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired, and shall be installed in accordance with the manufacturer's recommendations. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths (with the exception of the MSIVs, which are tested per SR 3.6.1.3.12) is less than or equal to the specified leakage rate. While the MSIVs are also classified as secondary containment bypass leakage pathway valves, they are evaluated according to SR 3.6.1.3.12, and if not within limits, actions are required to be taken in accordance with ACTION D. This provides assurance that the assumptions in the radiological evaluations that form the basis of the USAR (Ref. 2) 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 Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

Bypass leakage is considered part of L_a.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.12

The analyses in Reference 1 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ 24 scfh when tested at 40 psig. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

MSIV leakage is considered part of L_a.

SR 3.6.1.3.13

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 1 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 1 gpm times the total number of hydrostatically tested PCIVs when tested at ≥ 1.10 P_a (43.73 psig). The combined leakage rates must be demonstrated in accordance with the leakage test Frequency required by the 10 CFR 50 Appendix J Testing Program Plan. C

REFERENCES

1. Technical Requirements Manual.
2. USAR, Section 15.6.5.
3. USAR, Section 15.6.4.
4. USAR, Section 15.2.4. B
5. 10 CFR 50.36(c)(2)(ii).
6. USAR, Section 6.2.4.3.2.
7. 10 CFR 50, Appendix J Option B.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell and Suppression Chamber Pressure

BASES

BACKGROUND

The drywell and suppression chamber internal pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

Transient events, which include inadvertent drywell spray initiation, can reduce the drywell and suppression chamber internal pressure. Without an appropriate limit on the minimum drywell and suppression chamber internal pressure (14.2 psia), the design limit for negative containment differential pressure of 4.7 psid could be exceeded (Ref. 1).

The limitation on the maximum drywell and suppression chamber internal pressure (15.45 psia) provides added assurance that the peak LOCA drywell and suppression chamber pressure does not exceed the design value of 45 psig (Ref. 1).

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 2). Among the inputs to the design basis analysis is the initial drywell and suppression chamber internal pressure. The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of 45 psig and that peak negative pressure for an inadvertent drywell spray event does not exceed the design value of 4.7 psid.

Drywell and suppression chamber pressure satisfies Criterion 2 of Reference 3.

LCO

A limitation on the drywell and suppression chamber internal pressure of ≥ 14.2 psia and ≤ 15.45 psia is required to ensure that primary containment initial conditions are consistent with the initial safety analyses assumptions so that containment pressures remain within design values during a LOCA and the design value of containment negative pressure is not exceeded during an inadvertent operation of drywell sprays.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell and suppression chamber internal pressure within limits is not required in MODE 4 or 5.

ACTIONS

A.1

When drywell or suppression chamber internal pressure is not within the limits of the LCO, drywell and suppression chamber internal pressure must be restored to within limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell and suppression chamber internal 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 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that drywell and suppression chamber internal pressure is within limits ensures that operation remains within the limits assumed in the primary containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending primary 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 primary containment pressure condition.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR Section 6.2.
3. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND

Heat loads from the drywell, as well as piping and equipment, add energy to the airspace and raise airspace temperature. Coolers included in the unit design remove this energy and maintain an appropriate average temperature. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). This drywell air temperature limit is an initial condition input for the Reference 1 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for a entire spectrum of break sizes for postulated loss of coolant accidents (LOCAs) inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature. Analyses assume an initial average drywell air temperature of 150°F. Maintaining the expected initial conditions ensures that safety analyses remain valid and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 340°F (Ref. 1). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, and needed to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident.

In addition, the drywell average air temperature is the limiting initial condition used to determine the maximum negative differential pressure across the primary containment boundary following an inadvertent drywell spray actuation (Ref. 1).

Drywell air temperature satisfies Criterion 2 of Reference 2.

LCO

With an initial drywell average air temperature less than or equal to the LCO temperature limit, the peak accident temperature is maintained below the drywell design temperature and the design negative differential pressure B

(continued)

BASES

LCO (continued)	across the primary containment boundary is not exceeded. As a result, the ability of primary containment to perform its design function is ensured. 1/B
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> When drywell average air temperature is not within the limit of the LCO, it must be restored within 8 hours. This Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems. <u>B.1 and B.2</u> If the drywell average air temperature cannot be restored to within the limit 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 12 hours and to MODE 4 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	<u>SR 3.6.1.5.1</u> Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. In order to determine the drywell average air temperature, an arithmetic average is calculated, using measurements taken at locations within the drywell selected to provide a representative sample of the overall drywell atmosphere.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.1.5.1 (continued) The required locations are approximately as follows, in elevation and azimuth: 244 ft 0 inches, 110°; 244 ft 0 inches, 284°; 253 ft 11 inches, 169°; 255 ft 6 inches, 326°; 262 ft 3 inches, 28°; 268 ft 0 inches, 203°; 282 ft 6 inches, 243°; 283 ft 0 inches, 58°; 294 ft 5 inches, 117°; 296 ft 4 inches, 323°; 306 ft 9 inches, 189°; and 306 ft 9 inches, 354°. The 24 hour Frequency of this SR was developed based on operating experience related to drywell average air temperature variations and temperature dependent drift of instrumentation located in the drywell during the applicable MODES and the low probability of a DBA occurring between Surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal primary containment air temperature condition.
REFERENCES	1. USAR, Section 6.2.1.1.3. 2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Residual Heat Removal (RHR) Drywell Spray

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the suppression pool airspace, bypassing the suppression pool. The RHR Drywell Spray System is designed to mitigate the effects of bypass leakage. In addition, credit is taken for the turbulence induced by the sprays to ensure a well-mixed primary containment atmosphere during post-LOCA, which reduces the potential for a nonuniform hydrogen and oxygen concentration within the primary containment.

There are two redundant, 100% capacity RHR drywell spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, and one spray sparger inside the drywell. Dispersion of the spray water is accomplished by spray nozzles in each subsystem.

The RHR drywell spray mode will be manually initiated, if required, following a LOCA, according to emergency procedures.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be 0.054 ft^2. The analysis demonstrates that with drywell spray operation (in conjunction with RHR suppression pool spray operation) the primary containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	pressure remains within design limits. The RHR drywell spray mode also helps promote a uniform mixing of hydrogen and oxygen in the containment following a LOCA (Ref. 2). The RHR drywell spray satisfies Criterion 3 of Reference 3.
LCO	In the event of a Design Basis Accident (DBA), a minimum of one RHR drywell spray subsystem is required to mitigate potential bypass leakage paths, maintain the primary containment peak pressure below design limits, and ensures adequate mixing of the containment atmosphere. To ensure that these requirements are met, two RHR drywell spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR drywell spray subsystem is OPERABLE when the pump and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR drywell spray subsystems OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR drywell spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE RHR drywell spray subsystem is adequate to perform the primary containment bypass leakage mitigation and mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass leakage mitigation and mixing capability. The 7 day Completion Time was chosen in light of the redundant RHR drywell spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR drywell spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to reduce primary containment pressure and ensure adequate mixing in the primary containment are available.

C.1 and C.2

If any Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

Verifying the correct alignment for manual and power operated valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for 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. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR drywell spray mode is manually initiated. 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. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.1.6.2

Verifying, by administrative means, that each required RHR pump is OPERABLE ensures that the RHR pump is capable of performing its intended function (i.e., capable of developing the assumed drywell spray flow rate) when in the drywell spray mode. This Surveillance is met by verifying that another required Surveillance, which demonstrated the RHR pump OPERABILITY, was performed within the required Frequency. The verification can be performed by examining logs or other information, to determine if a required RHR pump is out of service for maintenance or other reasons. It is not necessary to perform an additional Surveillance needed to demonstrate the OPERABILITY of the required RHR pumps. The Frequency of 92 days is consistent with the normal RHR pump flow rate Surveillance Frequency ("in accordance with the Inservice Testing Program") in other Surveillances. C

SR 3.6.1.6.3 1C

This Surveillance is performed every 10 years to verify by performance of an air flow test that the spray nozzles in the drywell spray spargers are not obstructed and that flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Section 6.2.5.2.1.
3. 10 CFR 50.36(c)(2)(ii).

1C

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 8 vacuum breakers mounted in piping (two in series vacuum breakers per line) that connects the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a recirculation line break, or drywell spray actuation following a loss of coolant accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark II Vent System downcomer is controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is

(continued)

BASES

BACKGROUND (continued)

less than the suppression chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The vacuum breakers limit the height of the waterleg in the vent system during normal operation.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. Suppression chamber-to-drywell vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell floor.

The safety analyses assume that the vacuum breakers are closed initially and start to open at a differential pressure of 0.25 psid (Ref. 1). Both vacuum breakers in three of the four vacuum breaker lines must open to satisfy the design basis. The additional vacuum breaker line is provided to accommodate the postulated single failure of one vacuum breaker in a closed position (Ref. 1). The results of the analyses show that the design pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that eight vacuum breakers be OPERABLE are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and to remain closed and leak tight until the suppression pool is at a positive pressure relative to the drywell.

The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of Reference 2.

LCO

All vacuum breakers must be OPERABLE to provide assurance that the vacuum breakers will open so that drywell-to-suppression chamber negative differential pressure remains below the design value. This LCO also ensures that all suppression chamber-to-drywell vacuum breakers are closed (except during testing or when the vacuum breakers are

(continued)

BASES

LCO (continued)

performing their intended design function). The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell floor, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of drywell sprays.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one line with one or more vacuum breakers inoperable for opening (e.g., a vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining OPERABLE vacuum breakers in the other three lines are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers in the other three lines could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one or more of the vacuum breakers inoperable in one line, 72 hours is allowed to restore the inoperable vacuum breaker(s) to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

(continued)

BASES

ACTIONS (continued)

B.1

With one or more lines with one vacuum breaker not closed, communication between the drywell and suppression chamber airspace could occur, and, as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. 72 hours is allowed to close the vacuum breaker due to the redundant capability afforded by the other vacuum breaker in the same line, (the fact that the other vacuum breaker is closed), and the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of ≥ 0.25 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. As Noted, separate Condition entry is allowed for each vacuum breaker line.

C.1

With one or more lines with two vacuum breakers not closed, this allows communication between the drywell and suppression chamber, and as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, one open vacuum breaker must be closed. A short time is allowed to close one of the vacuum breakers due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of ≥ 0.25 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test. As Noted, separate Condition entry is allowed for each vacuum breaker line.

D.1 and D.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that a differential pressure of ≥ 0.25 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. This first Note allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The 31 day Frequency of this SR was developed, based on Inservice Testing Program requirements to perform valve testing at least once every 92 days. A 31 day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.2 (continued)

since they are located in a harsh environment (the suppression chamber airspace). In addition, this functional test is required within 12 hours after a discharge of steam to the suppression chamber from the safety/relief valves. | D

SR 3.6.1.7.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker opening (i.e., starts to open from the fully closed position) differential pressure of ≤ 0.25 psid is valid. 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. The 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. USAR, Section 6.2.1.
2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The primary containment utilizes a Mark II over/under pressure suppression configuration, with the suppression pool located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the design value (45 psig). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements. 1B

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation;

b. Primary containment peak pressure and temperature;

c. Condensation oscillation (CO) loads; and

d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the suppression pool temperature analyses required by Reference 3). An initial pool temperature of 90°F is assumed for the Reference 1 and 2 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

temperature of 120°F are assumed for the Reference 2 analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of Reference 4.

LCO

A limitation on the suppression pool average temperature is required to assure that the primary containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are as follows:

a. Average temperature ≤ 90°F with THERMAL POWER > 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ 105°F with THERMAL POWER > 1% RTP and testing that adds heat to the suppression pool is being performed. This requirement ensures that the plant has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 90°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 90°F is short enough not to cause a significant increase in plant risk.

c. Average temperature ≤ 110°F with THERMAL POWER ≤ 1% RTP. This requirement ensures that the plant will be shut down at > 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

At 1% RTP, heat input is approximately equal to normal system heat losses. C

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power limit, the initial conditions exceed the conditions assumed for the Reference 1 and 2 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > 90°F, increased monitoring of the pool temperature is required to ensure it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that suppression pool temperature increases relatively slowly except when testing that adds heat to the pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature 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, THERMAL POWER must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > 90°F with THERMAL POWER > 1% RTP when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, the testing must be immediately suspended to preserve the pool heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 within 36 hours is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when pool temperature is > 110°F, increased monitoring of pool temperature is required to ensure that it remains ≤ 120°F. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours and the plant must be brought to MODE 4 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.

Continued addition of heat to the suppression pool with pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

temperature or pressure. Furthermore, if a blowdown were to occur when temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of at least one OPERABLE post accident monitoring instrumentation channel in each suppression pool quadrant. Alternatively, average temperature can be determined by taking an arithmetic average of 10 OPERABLE suppression pool water temperature channels, which are distributed in different suppression pool sectors. There is no divisional requirement with respect to the instrument channels for this SR. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition. B B

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Appendix 6A.10.1.
3. NUREG-0783.
4. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The primary containment utilizes a Mark II over/under pressure suppression configuration, with the suppression pool located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling (RCIC) System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between 145,495 ft^3 at the low water level limit of 199 ft 6 inches and 154,794 ft^3 at the high water level limit of 201 ft.

If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the S/RV quenchers, main vents, or RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified.

If the suppression pool water level is too high, it could result in excessive clearing loads from S/RV discharges and excessive pool swell loads resulting from a Design Basis Accident (DBA) LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

APPLICABLE SAFETY ANALYSES

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Suppression pool water level satisfies Criteria 2 and 3 of Reference 2.
LCO	A limit that suppression pool water level be ≥ 199 ft 6 inches and ≤ 201 ft (referenced to mean sea level) is required to ensure that the primary containment conditions assumed for the safety analysis are met. Either the high or low water level limits were used in the safety analysis, depending upon which is conservative for a particular calculation.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced because of the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS—Shutdown."

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analysis are not met. If water level is below the minimum level, the pressure suppression function still exists as long as the downcomers are covered, RCIC turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis and the capability of the drywell and suppression pool sprays. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within specified limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.

B.1 and B.2

If suppression pool water level 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

(continued)

BASES

ACTIONS	B.1 and B.2 (continued) achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.6.2.2.1 Verification of the suppression pool water level is to ensure that the required limits are satisfied. The 24 hour Frequency has been shown to be acceptable based on operating experience. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.
REFERENCES	1. USAR, Section 6.2. 2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each RHR subsystem contains a pump and a heat exchanger and is manually initiated and independently controlled. The two RHR subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchanger and returning it to the suppression pool. Service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the ultimate heat sink.

The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to 212°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or a stuck open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	suppression pool temperature is calculated to remain below the design limit. The RHR Suppression Pool Cooling System satisfies Criterion 3 of Reference 2.
LCO	During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when the pump, a heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause both a release of radioactive material to primary containment and a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining RHR suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR suppression pool cooling subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment pressure and temperature mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and the potential avoidance of a plant shutdown transient that could result in the need for the RHR suppression pool cooling subsystems to operate.

C.1 and C.2

If any Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual and power operated valves in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. 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 prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. 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. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1 (continued)

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable, based on operating experience.

SR 3.6.2.3.2

Verifying each required RHR pump develops a flow rate $\geq$ 7450 gpm, while operating in the suppression pool cooling mode with flow through the associated heat exchanger, ensures that the primary containment peak pressure and temperature can be maintained below the design limits during a DBA (Ref. 1). The flow is also a normal test of centrifugal pump performance required by ASME Section XI (Ref. 3). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice tests confirm component OPERABILITY and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. USAR, Section 6.2.
2. 10 CFR 50.36(c)(2)(ii).
3. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Spray System removes heat from the suppression chamber airspace. The suppression pool is designed to absorb the sudden input of heat from the primary system from a DBA or a rapid depressurization of the reactor pressure vessel (RPV) through safety/relief valves. The heat addition to the suppression pool results in increased steam in the suppression chamber, which increases primary containment pressure. Steam blowdown from a DBA can also bypass the suppression pool and end up in the suppression chamber airspace. Some means must be provided to remove heat from the suppression chamber so that the pressure and temperature inside primary containment remain within analyzed design limits. This function is provided by two redundant (except for the spray header, which is common) RHR suppression pool spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two RHR suppression pool spray subsystems contains one pump, which is manually initiated and independently controlled. The two subsystems perform the suppression pool spray function by circulating water from the suppression pool to the suppression pool spray sparger. The suppression pool spray sparger is common to both subsystems. The sparger only accommodates a small portion of the total RHR pump flow; the remainder of the flow returns to the suppression pool through the suppression pool cooling return line (provided the associated valve is open). Thus, both suppression pool cooling and suppression pool spray functions are normally performed when the Suppression Pool Spray System is initiated. Either RHR suppression pool spray subsystem is sufficient to condense the steam from small bypass leaks from the drywell to the suppression chamber airspace during the postulated DBA.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break loss of coolant accidents. The intent of the analyses is to demonstrate that the pressure reduction capacity of the RHR Suppression Pool Spray System (in conjunction with the RHR Drywell Spray System) is adequate to maintain the primary containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit. The RHR suppression pool spray satisfies Criterion 3 of Reference 2.
LCO	In the event of a DBA, a minimum of one RHR suppression pool spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool spray subsystem is OPERABLE when one pump and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR suppression pool spray subsystems OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE RHR suppression pool spray subsystem is adequate to perform the primary containment bypass leakage mitigation function.

(continued)

BASES

ACTIONS

A.1 (continued)

However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass mitigation capability. The 7 day Completion Time was chosen in light of the redundant RHR suppression pool spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1

With both RHR suppression pool spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to reduce pressure in the primary containment are available.

C.1 and C.2

If any Required Action and associated Completion Time cannot be 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 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying the correct alignment for manual and power operated valves in the RHR suppression pool spray mode flow path provides assurance that the proper flow paths will exist for system operation. 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 prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1 (continued)

acceptable since the RHR suppression pool cooling mode is manually initiated. 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. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.4.2

Verifying each required RHR pump develops a flow rate ≥ 450 gpm while operating in the suppression pool spray mode helps ensure that the primary containment pressure can be maintained below the design limits during a DBA (Ref. 1). The normal test of centrifugal pump performance required by Section XI of the ASME Code (Ref. 3) is covered by the requirements of LCO 3.6.2.3, "RHR Suppression Pool Cooling." The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. USAR, Section 6.2.2.2.
2. 10 CFR 50.36(c)(2)(ii).
3. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiners

BASES

BACKGROUND

The primary containment hydrogen recombiners eliminate the potential breach of primary containment due to a hydrogen oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombiners are required to reduce the hydrogen and oxygen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombiners accomplish this by recombining hydrogen and oxygen to form water vapor. The vapor is cooled and returned to the suppression pool, thus eliminating any discharge to the environment. The primary containment hydrogen recombiner is manually initiated, since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent primary containment hydrogen recombiner subsystems are provided. Each consists of controls located in the control room, a power supply, and a recombiner located in the reactor building. Recombination is accomplished by heating a hydrogen air mixture to > 1150°F. The resulting water vapor and discharge gases are cooled prior to discharge from the unit. Air flows through the unit at approximately 150 scfm, with a blower providing the motive force. A single recombiner is capable of maintaining the hydrogen and oxygen concentration in primary containment to ≤ 5.0 volume percent (v/o) (Ref. 3). Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate emergency bus and is provided with separate power panel and control panel.

Operating Procedures direct that the hydrogen and oxygen concentration in primary containment be monitored following a DBA and that the primary containment hydrogen recombiners be manually activated prior to the primary containment atmosphere reaching a bulk hydrogen and oxygen concentrations of 4.0 v/o and 4.5 v/o, respectively.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The primary containment hydrogen recombiners provide the capability of controlling the bulk hydrogen and oxygen concentrations in primary containment to less than a concentration of 5.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen/oxygen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen and oxygen generation is a LOCA.

Oxygen may accumulate in the primary containment following a LOCA as a result of:

a. Radiolytic decomposition of water in the Reactor Coolant System; or

b. Operation of relief valves in the Breathing and Service Air Systems.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System; or

c. Corrosion of metals and decomposition of organic materials in the primary containment.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Assumptions recommended by Reference 4 are used to maximize the amount of hydrogen calculated.

The calculation confirms that when the mitigating systems are actuated in accordance with plant procedures, the peak hydrogen and oxygen concentrations in the primary containment remains ≤ 5.0 v/o (Ref. 3).

The primary containment hydrogen recombiners satisfy Criterion 3 of Reference 5.

(continued)

BASES (continued)

LCO

Two primary containment hydrogen recombiners must be OPERABLE. This ensures operation of at least one primary containment hydrogen recombiner in the event of a worst case single active failure.

Operation with at least one primary containment hydrogen recombiner subsystem ensures that the post LOCA hydrogen and oxygen concentrations can be prevented from exceeding their flammability limit.

APPLICABILITY

In MODES 1 and 2, the two primary containment hydrogen recombiners are required to control the hydrogen and oxygen concentrations within primary containment below their limit of 5.0 v/o following a LOCA, assuming a worst case single failure.

In MODE 3, both the hydrogen and oxygen production rate and the total hydrogen and oxygen production after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiners are not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiners are not required in these MODES.

ACTIONS

A.1

With one primary containment hydrogen recombiner inoperable, the inoperable primary containment hydrogen recombiner must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE primary containment recombiner is adequate to perform the hydrogen and oxygen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen and oxygen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the amount of time available after the event for operator action to prevent hydrogen and oxygen

(continued)

BASES

ACTIONS

A.1 (continued)

accumulation exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note stating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the low probability of the failure of the OPERABLE recombiner, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limits.

B.1 and B.2

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen and oxygen control function via an alternate capability must be verified by administrative means within 1 hour. The alternate hydrogen and oxygen control capability is provided by the Primary Containment Vent, Purge, and Nitrogen System and one RHR drywell spray subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen and oxygen control function does not exist. In addition, the alternate hydrogen and oxygen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen and oxygen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen and oxygen control system. If the ability to perform the hydrogen and oxygen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen and oxygen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in the amounts capable of exceeding the flammability limits.

(continued)

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time cannot be 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the minimum heater coil outlet gas temperature increases to ≥ 1150°F in ≤ 1.5 hours and that it is maintained ≥ 1150°F for ≥ 4 hours to check the capability of the recombiner to properly function (and that significant heater elements are not burned out).

Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.2

This SR requires performance of a resistance to ground test of each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 1.0E6 ohms, within 30 minutes following completion of a system functional test (SR 3.6.3.1.1) or heatup of the system to normal operating temperature.

Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. USAR, Section 6.2.5.
4. Regulatory Guide 1.7, Revision 2, November 1978.
5. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND

The primary containment is designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 4.0 v/o works together with the Hydrogen Recombiner System (LCO 3.6.3.1, "Primary Containment Hydrogen Recombiners") and the RHR Drywell Spray System (LCO 3.6.1.6, "RHR Drywell Spray") to provide redundant and diverse methods to mitigate events that produce hydrogen and oxygen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain ≤ 5.0 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment, except that the hydrogen recombiners remove hydrogen and oxygen gases faster than they can be produced from radiolysis and again no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions. B

APPLICABLE SAFETY ANALYSES

The Reference 1 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, is recombined by the hydrogen recombiners (LCO 3.6.3.1) more rapidly than it is produced.

Primary containment oxygen concentration satisfies Criterion 2 of Reference 2.

(continued)

BASES (continued)

LCO

The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen and oxygen does not result in a combustible mixture inside primary containment.

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen and oxygen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is < 15% RTP, the potential for an event that generates significant hydrogen and oxygen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4.0 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the availability of other hydrogen and oxygen mitigating systems (e.g., hydrogen recombiners) and the low probability and long duration of an event that would generate significant amounts of hydrogen and oxygen occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

If oxygen concentration 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, power must be reduced to ≤ 15% RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

The primary containment must be determined to be inerted by verifying that oxygen concentration is < 4.0 v/o. The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which could lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.5.

2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment (consisting of the reactor building and auxiliary bay structures) is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid, with the exception of the ASME III Code Class 1 piping and valves in the steam tunnel (Ref. 1). This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump/motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABLE SAFETY ANALYSES

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 2), and a fuel handling accident (Ref. 3). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	and that fission products entrapped within the secondary containment structure will be treated by the SGT System prior to discharge to the environment. Secondary containment satisfies Criterion 3 of Reference 4.
LCO	An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.
APPLICABILITY	In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY. In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.
ACTIONS	A.1 If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary

(continued)

BASES

ACTIONS

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If the secondary 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 12 hours and to MODE 4 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, C.2, and C.3

Movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of 1C

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. C

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases, a secondary containment barrier contains multiple inner or multiple outer doors. For these cases, the access openings share the inner door or the outer door, i.e., the access openings have a common inner door or outer door. The intent is not to breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times; i.e., all inner doors closed or all outer doors closed. Thus, each access opening has one door closed. However all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.2 and SR 3.6.4.1.3 (continued)

performed on an access opening. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to draw down pressure in the secondary containment to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds and maintain pressure in the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 2670 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that the secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds with the initial secondary containment pressure ≥ 0 psig, using one SGT subsystem. SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm. This flow rate is the assumed secondary containment leak rate during the drawdown period. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The drawdown test conditions must be adjusted based on the methodology in Reference 5 to compensate for actual inleakage flow and initial conditions during the test. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes these Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

C

C

REFERENCES

1. USAR, Section 3.6A.2.1.5.
2. USAR, Section 15.6.5.
3. USAR, Section 15.7.4.
4. 10 CFR 50.36(c)(2)(ii).
5. USAR, Section 6.2.3.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Refs. 1 and 2). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, that are released during certain operations when primary containment is not required to be OPERABLE, or that take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

Automatic SCIVs (i.e., dampers) close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges (which includes plugs and caps as listed in Reference 3). B

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a fuel handling accident (Ref. 2). The secondary containment performs no active function in response to each of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment. SCIVs satisfy Criterion 3 of Reference 4. 1B
LCO	SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs. The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3. 1C The normally closed manual SCIVs are considered OPERABLE when the valves are closed and blind flanges in place, or open under administrative controls. These passive isolation valves or devices are listed in Reference 3. 1A 1C
APPLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required. In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.
ACTIONS	The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is

(continued)

BASES

ACTIONS (continued)

in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when the need for secondary containment isolation is indicated.

The second Note provides clarification that, for the purpose of 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 SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) 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 criteria are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. This Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. 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 automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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, D.2, and D.3

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. C

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1 (continued)

added assurance that the SCIVs are in the correct positions. 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. A

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low. B

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

SR 3.6.4.2.2

Verifying the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 92 days.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.3 (continued)

Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. Technical Requirements Manual. B
4. 10 CFR 50.36(c)(2)(ii). B

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The SGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

a. A moisture separator;

b. An electric heater;

c. A prefilter bank;

d. A high efficiency particulate air (HEPA) filter bank;

e. A charcoal adsorber bank;

f. A second HEPA filter bank; and

g. A centrifugal fan.

The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis. The internal pressure of the SGT System boundary region is maintained at a negative pressure of ≥ 0.25 inch water gauge when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building.

The moisture separator is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to less than 70% (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter is provided to remove fine particulate matter and

(continued)

BASES

BACKGROUND (continued)	protect the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter is provided to collect any carbon fines exhausted from the charcoal adsorber. The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both fans will start and the associated train inlet and fan discharge valves will open. Negative pressure in the reactor building is automatically controlled by the SGT System filter train recirculation line pressure control valves.
APPLICABLE SAFETY ANALYSES	The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents (Refs. 3 and 4). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment. The SGT System satisfies Criterion 3 of Reference 5.
LCO	Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two OPERABLE subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

(continued)

BASES (continued)

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, 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 12 hours and to MODE 4 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, C.2.1, C.2.2, and C.2.3

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation will occur, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the unit in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable,

(continued)

BASES

ACTIONS

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

action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1, E.2, and E.3

When two SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating (from the control room using the manual initiation switch) each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system. 1 B

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 6). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.3.4

This SR requires verification that the SGT decay heat removal air inlet valves can be opened. This ensures that the decay heat removal mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.5.1.2.2.
3. USAR, Section 15.6.5.
4. USAR, Section 15.7.4.
5. 10 CFR 50.36(c)(2)(ii).
6. Regulatory Guide 1.52, Rev. 2.

A.1

Specification 3.6.1.1

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITIONS FOR OPERATION

3.6.1.2 (Continued)

ACTION:

Condition A

b. The measured combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steam line isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests equaling or exceeding 0.60 La, or A.4 moved to Specification 5.5.12

c. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, or A.5 moved to LCO 3.6.1.3

d. The measured leakage rate through any valve that is part of a potential bypass leakage pathway exceeding the limit specified in Table 3.6.1.2-1

Restore: within 1 hour A.2

Required Action A.1

a. The overall integrated leakage rate to less than 1.0 La, and A.4 moved to Specification 5.5.12

b. The combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steamline isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests to less than 0.60 La and A.4 moved to Specification 5.5.12

c. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves, and A.5 moved to LCO 3.6.1.3

d. The leakage rate to less than or equal to that specified in Table 3.6.1.2-1 for any valve that is part of a potential bypass leakage path. Alternatively, in lieu of restoring the inoperable valve to OPERABLE status, isolate the affected bypass leakage path by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. The isolation device must meet the leakage limit of Table 3.6.1.2-1 associated with the inoperable valve. Enter applicable ACTION statement(s) for system(s) made inoperable by isolating a bypass leakage path. D

* Exemption to Appendix J to 10 CFR 50. A.4 moved to Specification 5.5.12

Page 3 of 10

A.1

Specification 3.6.1.3

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITIONS FOR OPERATION

3.6.1.2 (Continued)

See Discussion of Changes for ITS: 3.6.1.1, in this section.

ACTION:

b. The measured combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steam line isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests equaling or exceeding 0.60 La, or

Condition D c. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding ~~1 gpm times the total number of such valves~~ or limits LA.4 C

Condition D d. The measured leakage rate through any valve that is part of a potential bypass leakage pathway exceeding the limit specified in Table 3.6.1.2-1 LA.3 purge valves only D

Restore: A.12 D

a. The overall integrated leakage rate to less than 1.0 La, and

b. The combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steamline isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests to less than 0.60 La, and

Required Action D.1 c. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to ~~less than or equal to 1 gpm times the total number of such valves~~, and within limits LA.4 C A.12 D

Required Action D.1 d. The leakage rate to less than or equal to that specified in Table 3.6.1.2-1 ~~for any valve that is part of a potential bypass leakage path~~. Alternatively, in lieu of restoring the inoperable valve to OPERABLE status, isolate the affected bypass leakage path by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. The isolation device must meet the leakage limit of Table 3.6.1.2-1 associated with the inoperable valve. LA.3 purge valves only A.12 D

ACTIONS NOTE 3 Enter applicable ACTION statement(s) for system(s) made inoperable by isolating a bypass leakage path.

extend Completion Times from 1 hour to 4 hours for hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage, 8 hours for MSIV leakage, and 72 hours for hydrostatically tested line leakage on a closed system L.12

add proposed Required Action D.2 M.4

* Exemption to Appendix J to 10 CFR 50.

See Discussion of Changes for ITS: 3.6.1.1, in this section.

D B

A.13

Specification 3.6.1.3

Table 3.6.1.3-1

TABLE 3.6.1.2-1 (Continued)

ALLOWABLE LEAK RATES THROUGH VALVES IN

POTENTIAL BYPASS LEAKAGE PATHS

LINE DESCRIPTION	VALVE MARK NO.	TERMINATION REGION	PER VALVE LEAK RATE, SCFH
Inst. Air to ADS Valve Accumulator	IAS*SOV164 IAS*V448	Yard Area	0.9375
Inst. Air to ADS Valve Accumulator	IAS*SOV165 IAS*V449	Yard Area	0.9375
N_2 Purge to TIP Index Mechanism	GSN*SOV166 GSN*V170	Yard Area	*
Inst. Air to SRV Accumulator	IAS*SOV166 IAS*SOV184	Yard Area	*
Inst. Air to Drywell	IAS*SOV167 IAS*SOV185	Yard Area	*
Inst. Air to Drywell	IAS*SOV168 IAS*SOV180	Yard Area	*
Inst. Air to CPS Valve in Suppression Chamber	CPS*SOV132 CPS*V50	Yard Area	*
Inst. Air to CPS Valve in Suppression Chamber	CPS*SOV133 CPS*V51	Yard Area	*

L.13

L.13

footnote(a) to Table 3.6.1.3-1

* The combined leakage of these six penetrations shall not exceed 3.6 SCFH. The leakage through each penetration shall be that of the valve with the highest rate in that penetration. However, if a penetration is isolated by one closed and de-activated automatic valve, closed manual valve, or blind flange, the leakage through the penetration shall be that of the isolation device.

D

A.1

Specification 3.6.1.3

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT PURGE SYSTEM

LIMITING CONDITIONS FOR OPERATION

LCO 3.6.1.3 3.6.1.7 The drywell and suppression chamber 12-inch and 14-inch purge supply and exhaust isolation valves shall be OPERABLE and: A.8

Note to SR 3.6.1.3.1

a. The 12-inch (2CPS*AOV105, 2CPS*AOV107, 2CPS*AOV109, 2CPS*AOV111) and 14-inch (2CPS*AOV104, 2CPS*AOV106, 2CPS*AOV108, 2CPS*AOV110) valves in the purge system supply and exhaust lines may be open for up to 135 hours per 365 days for VENTING or PURGING.* L.15

b. Purge system valves 2CPS*AOV105 (12-inch), 2CPS*AOV107 (12-inch), 2CPS*AOV109 (12-inch), and 2CPS*AOV110 (14-inch) shall be blocked to limit the opening to 70°. Purge system valve 2CPS*AOV111 (12-inch) shall be blocked to limit the opening to 60°. L.16

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3. L.5

ACTION:

add proposed ACTIONS Note 1 A.2

add proposed ACTIONS Note 2

add proposed ACTIONS Note 4 A.3

B

Actions A and B

a. With the drywell and suppression chamber purge supply and/or exhaust isolation valve(s) inoperable, ~~or open for more than 135 hours per 365 days for other than pressure control*,~~ close the open valve(s); otherwise isolate the penetration(s) within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. L.15 M.2

Action F

b. With a drywell and suppression chamber purge ~~supply and/or~~ exhaust isolation valve(s) with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirement 4.6.1.7.2, ~~restore the inoperable valve(s) to OPERABLE status within 24 hours~~ or isolate the affected purge system line by use of one closed and de-activated automatic valve, closed manual valve, or blind flange within 24 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. If a valve with resilient seals is utilized to satisfy the requirement of this ACTION statement, it must have been demonstrated to meet the leakage requirement of SR 4.6.1.7.2. In addition, SR 4.6.1.7.2 must be performed once per 92 days for the resilient seal valve closed to comply with this ACTION statement. Enter the applicable ACTION statement(s) for system(s) made inoperable by isolating the affected purge system line. L.12 A.5

Action E

Action F

Action E and Required Actions D.1 and D.3

Actions Note 3

add proposed Required Action E.2 M.4

D

Note to SR 3.6.1.3.1

* The 135-hour limit shall not apply to the use of valves 2CPS*AOV108 (14-inch) and 2CPS*AOV110 (14-inch), or 2CPS*AOV109 (12-inch) and 2CPS*AOV111 (12-inch), for primary containment pressure control, provided 2GTS*AOV101 is closed, and its 2-inch bypass line is the only flow path to the standby gas treatment system. L.15

ADMINISTRATIVE (continued)

A.5 The revised presentation of CTS 3.6.1.3 Actions a.1 and b.1, CTS 3.4.7 Action a.1.a, and CTS 3.6.1.7 Action b (based on the BWR Standard Technical Specifications, NUREG-1434, Rev. 1) does not explicitly detail options to "restore...to OPERABLE status." This action is always an option, and is implied in all Actions. Omitting these actions from the ITS is editorial. D

A.6 The allowance in CTS 3.6.3 Actions a.4 and b, and CTS 3.4.7 Action b, which states that the provisions of Specification 3.0.4 are not applicable has been deleted since proposed LCO 3.0.4 provides this allowance (i.e., this allowance has been moved to LCO 3.0.4). The LCO 3.0.3 statement in CTS 3.6.3 Action b has been deleted since it is redundant to the "Otherwise..." action. That is, LCO 3.0.3 is not applicable anyway since a shutdown action has been provided. Therefore, deletion of these allowances is administrative.

A.7 CTS 4.3.7.7.c requires all the squib charges in the TIP System shear valves to be tested once per 90 months, with at least one squib being tested every 18 months. CTS 4.6.3.5.b requires each squib charge in each shear valve to be tested every 36 months, with at least one squib being tested every 18 months. Since the Frequency of CTS 4.6.3.5.b is more limiting, the CTS 4.3.7.7.c Frequency has been changed to be consistent with CTS 4.6.3.5.b, except as discussed below. Since the Frequency of CTS 4.6.3.5.b is more limiting than that of CTS 4.3.7.7.c, this part of the change is considered administrative. Proposed SR 3.6.1.3.10 will require one squib from each shear valve to be tested every 24 months on a staggered test basis (which ensures both squibs in each valve are tested every 48 months). The change in Frequency from 18 months to 24 months, and from 36 months to 48 months is discussed in Discussion of Change LD.1 below.

A.8 CTS 3.4.7 and 3.6.1.7 repeat most of the requirements, provisions, and actions for MSIVs and purge valves, respectively, separate from all other primary containment isolation valves in CTS 3.6.3. The ITS incorporate these requirements and associated restoration times into ITS 3.6.1.3, the primary containment isolation valve Specification. This is a presentation preference, except as noted by other Discussion of Changes for ITS: 3.6.1.3.

A.9 The test method (i.e., with air or nitrogen) in CTS 4.6.1.2.2 is consistent with the requirements of 10 CFR 50, Appendix J, and are therefore, not necessary to be placed in the surveillance. Since the test method is prescribed in the regulation, its removal is considered administrative.

A.10 The surveillance frequency of CTS 4.6.1.2.2 and 4.6.1.2.3 is specified in accordance with the 10 CFR 50 Appendix J Testing Program in CTS 6.8.4.f (ITS 5.5.12). The requirement of CTS 4.6.1.2.4 stating the provisions of

ADMINISTRATIVE

A.10 (cont'd) Specification 4.0.2 are not applicable to these Surveillance Requirements (proposed SR 3.6.1.3.6, SR 3.6.1.3.11, SR 3.6.1.3.12, and SR 3.6.1.3.13) is not required since it is stated in the proposed 10 CFR 50 Appendix J Testing Program in ITS 5.5.12. Any changes to this requirement are discussed in ITS: 5.5, "Programs and Manuals."

A.11 CTS Table 3.6.1.2-1 lists the allowable leakage rate for the MSIVs. These limits are provided in proposed SR 3.6.1.3.12. Therefore, there is no reason to include them in ITS Table 3.6.1.3-1. Since this is a presentation preference only, this change is considered administrative.

A.12 The revised presentation of CTS 3.6.1.2 Action (Restore) d (based on the BWR Standard Technical Specifications, NUREG-1434, Rev. 1) does not explicitly detail options to "restore...to OPERABLE status." This action is always an option, and is implied in all Actions. Omitting these actions from the ITS is editorial. In addition, CTS 3.6.1.2 Action (Restore) c has been modified in ITS 3.6.1.3 Required Action D.1 to require isolation of the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. This proposed Action is equivalent to the current restore action since the Note to ITS 3.6.1.3 Required Action D.1 requires that the isolation device used to satisfy Required Action D.1 must be verified to meet the applicable leakage rate limit of the inoperable valve. Thus, isolating the affected penetration with a device that meets the required leakage limits effectively restores the leakage rate to within limits, as is required by CTS. This allowance (to allow restoration to be met by isolating the penetration with a device that meets the applicable leakage limits) is also provided in the ISTS Bases for the hydrostatically tested line leakage ACTION (ISTS 3.6.1.3 ACTION D.1 Bases). Therefore, this change is also administrative. D

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 An additional Applicability has been added to ITS 3.6.1.3 (i.e., when associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation"), which effectively adds a MODE 4 and 5 requirement to the RHR Shutdown Cooling System isolation valves. Operability of these valves is necessary to preclude an inadvertent

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) draindown of the reactor vessel through the shutdown cooling isolation valves from lowering reactor vessel water level to the top of the fuel. Appropriate ACTIONS have been added (ITS 3.6.1.3 ACTION G) for when the valves cannot be isolated or restored within the current 4 hour limit. Since the unit is already in MODE 4 or 5, the CTS 3.6.3 shutdown action would not provide any restriction. This change is an additional restriction on plant operation.

M.2 CTS 3.6.1.7 Action a requires the affected penetration to be isolated within 4 hours if the purge valve(s) are inoperable. This includes being open for reasons other than allowed in the CTS LCO statement. ITS 3.6.1.3 Required Action B.1 will only allow 1 hour to isolate the affected penetration if both purge valves in a penetration are open for reasons other than those allowed in SR 3.6.1.3.1. (While ITS 3.6.1.3 ACTION B applies to inoperable PCIVs, the purge valves are considered inoperable if they are open for reasons other than those allowed in SR 3.6.1.3.1; thus ACTION B would apply). This will ensure that the primary containment boundary is reestablished in a short time, consistent with other primary containment degradations. This change is more restrictive on plant operations.

M.3 A new Surveillance Requirement has been added. This Surveillance Requirement (SR 3.6.1.3.1) verifies the 12 and 14 inch purge valves are closed every 31 days (except when allowed to be open, as described in Discussion of Change L.14 below). This will ensure the valves are in their accident position, thus helping to ensure the offsite releases are within the limits if a LOCA were to occur. This SR is an additional restriction on plant operation.

M.4 ITS 3.6.1.3 Required Actions D.2 and E.2 are being added. These Required Actions require the affected penetration flow path to be verified isolated a) every 31 days for isolation devices outside containment, and b) prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside containment. This will ensure the penetration remains isolated. This is an additional restriction on plant operations. 1

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 CTS 4.6.3.3 requires the isolation time of power operated and automatic PCIVs to be verified within limits when tested pursuant to Specification 4.0.5 (the Inservice Test (IST) Program requirements). The requirement to stroke time test the power operated, non-automatic, PCIVs has been relocated to the IST

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) Program. The ISTS Bases for SR 3.6.1.3.5 state that the "isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analysis." Certain power operated PCIVs do not receive an automatic isolation signal, and their time is not assumed in the safety analysis, since it requires operator action to close the valves. Due to this, in the NMP2 PCIV table (which is located outside of Technical Specifications), the isolation time for the power operated, non-automatic valves are listed as "NA." However, the IST Program, required by 10 CFR 50.55a, provides requirements for the testing of all ASME Code Class 1, 2, and 3 valves in accordance with applicable codes, standards, and relief requests, endorsed by the NRC for NMP2. Testing of the power operated, non-automatic valves includes applicable stroke times. Compliance with 10 CFR 50.55a, and as a result the IST Program and implementing procedures, is required by the NMP2 Operating License. These controls are adequate to ensure the required testing to demonstrate OPERABILITY is performed. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the relocated requirements in the IST Program will be controlled by the provisions of 10 CFR 50.59 and 10 CFR 50.55a.

LA.2 Requirements in CTS 4.6.3.5.b and 4.3.7.7.c concerning the replacement charges for the traversing in-core probe (TIP) explosive valves are proposed to be relocated to the Bases. These details are not necessary to ensure that the TIP System explosive isolation valves are maintained OPERABLE. The requirements of ITS 3.6.1.3, SR 3.6.1.3.4, and SR 3.6.1.3.10 are adequate to ensure the OPERABILITY of the TIP system explosive isolation valves. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.3 The allowable leak rates through resilient seal purge valves in potential bypass leakage paths identified in CTS Table 3.6.1.2-1 and CTS 4.6.1.7.2 and the leak rate test pressures in CTS 3.6.1.2.d, CTS 3.6.1.2 Action d, 4.6.1.2.2, and 4.6.1.7.2 are proposed to be relocated to the Bases. The listing of valves, associated leakage limits, and test pressure are related to design and are not necessary for ensuring the test is performed. The requirements of CTS 3.6.1.2.d, 4.6.1.2.2 and 4.6.1.7.2 have been maintained in proposed SR 3.6.1.3.6, which ensures the proper tests are performed for the primary containment purge valves with resilient seals. This formatting change has been made in accordance with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Therefore, the relocated requirements are not required

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.3 (cont'd) to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.4 Requirements in CTS LCO 3.6.1.2.c, 3.6.1.2 Action c (including the Restore portion of the Action), and 6.8.4.f.3 concerning the leakage limit and test pressure for valves in hydrostatically tested lines are proposed to be relocated to the Bases. The leakage limits and test pressure are not necessary for ensuring the test is performed. The requirements of ITS 3.6.1.3 and SR 3.6.1.3.13 are adequate to ensure the OPERABILITY of these valves and that they are tested properly. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.5 The requirement to perform CTS 4.6.3.2 during COLD SHUTDOWN or REFUELING has been relocated to the Bases in the form of a statement that the Surveillance shall be performed in MODE 4 or 5. The proposed Surveillance (for a functional test of each primary containment isolation valve) does not include the restriction on plant conditions. Some isolation valves could be adequately tested in other than Cold Shutdown or Refueling, without jeopardizing safe plant operations. The control of the plant conditions appropriate to perform the test is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance. Therefore, the relocated requirement is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LD.1 The Frequencies for performing CTS 4.6.3.2, 4.6.3.4, 4.6.3.5.b, and 4.3.7.7.c have been extended from 18 months to 24 months in proposed SRs 3.6.1.3.8, 3.6.1.3.9, and 3.6.1.3.10 to facilitate a change to the NMP2 refuel cycle from 18 months to 24 months. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (36 month for CTS 4.6.3.5.b) (i.e., a maximum of 22.5 months (45 months for CTS 4.6.3.5.b) accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (48 months for SR 3.6.1.3.10) (i.e., a maximum of 30 months (60 months for SR 3.6.1.3.10) accounting for the allowable grace period specified in CTS 4.0.2 and proposed Specification 3.0.2). This proposed

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies (48 month for SR 3.6.1.3.10), if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months or 60 months, as applicable) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 CTS 3.6.3 Action a requires an inoperable PCIV to be restored or the affected penetration isolated in 4 hours. CTS 3.4.7 Action a also requires an inoperable MSIV (which is a PCIV) to be restored or the affected penetration isolated in 4 hours. ITS 3.6.1.3 Required Action A.1 allows 8 hours to isolate the affected penetration when an MSIV is inoperable, and ITS Required Action C.1 (second Completion Time) allows 72 hours to isolate the affected penetration when a PCIV is inoperable in a penetration with a closed system and only one PCIV. For the MSIVs, the additional 4 hours provides more time to restore the inoperable MSIV given the fact that MSIV closure will result in isolation of the affected main steam line and potential for a plant shutdown. The additional time is reasonable since the penetration can still be isolated using the other MSIV and the low probability of a main steam line break. For PCIVs in a penetration with a closed system and only one PCIV, they are either in a closed system, as specifically defined in NUREG-0800 (the Standard Review Plan), section 6.2.4, or they are in a penetration whose system piping communicates with the suppression pool and is expected to remain submerged during the accident (i.e., a closed system as defined in the USAR). The NRC has allowed this design for NMP2 and other BWRs and, while the reason these types of penetrations meet the requirements of the General Design Criteria (GDC) is not specifically described in the Standard Review Plan, they meet the GDC requirements for being classified as a closed system outside the containment because they satisfy "other defined bases" established by the NRC to meet the GDC requirements. The additional time is reasonable for the closed system valves since the intact piping or the water seal acts as the penetration isolation barrier and ensures that the primary containment boundary is maintained intact until another barrier can be established to isolate the penetration. This additional time also avoids the potential for a plant shutdown and provides time

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) to repair the inoperable PCIV in lieu of isolating the penetration (which could result in an inoperable ECCS subsystem, since the water sealed PCIVs are only in ECCS penetrations).

L.2 CTS 3.6.3 Action a, CTS 3.4.7 Action a, and CTS 4.6.1.1.b list some, but not all, of the possible acceptable isolation devices that may be used to satisfy the need to isolate a penetration with an inoperable isolation valve. ITS 3.6.1.3 ACTIONS provide a complete list of acceptable isolation devices. Since the result of the ACTIONS continues to be an acceptably isolated penetration for continued operation, the proposed change does not adversely affect safe operation. Many penetrations are designed with check valves as acceptable isolation barriers. With forward flow in the line secured, a check valve is essentially equivalent to a closed manual valve. For those penetrations designed with check valves as acceptable isolation devices, the ITS provides an equivalent level of safety. For penetrations not designed with check valves for isolation, the ITS does not affect the requirements to isolate with a closed deactivated automatic valve, closed manual valve, or blind flange. ITS ACTIONS allowing closed manual valves or check valves with flow secured also apply to isolating main steam lines, even though the design does not provide for these type of isolation devices. This change is simply a result of simplicity in providing a consistent presentation for all penetrations. While this apparent flexibility does not result in any actual technical change in the Technical Specifications, it is listed here for completeness.

L.3 In the event two or more valves in a penetration are inoperable, CTS 3.6.3 Action a, which requires maintaining one isolation valve OPERABLE, would not be met and an immediate shutdown would be required. ITS 3.6.1.3 ACTION B provides 1 hour prior to commencing a required shutdown. This proposed 1 hour period is consistent with the existing time allowed for conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various primary containment degradations. This change to CTS 3.6.3 is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which continued operation is allowed and the capability to isolate a primary containment penetration is lost.

L.4 CTS 3.6.3 Action b allows 4 hours to either repair the inoperable excess flow check valve or isolate the associated instrument. ITS 3.6.1.3 Required Action C.1 has extended this time to 72 hours. In this event, a limiting event would still be assumed to be within the bounds of the safety analysis (the excess flow lines contain orifices and are approximately ¼ inch in diameter.) Allowing an extended restoration time, to potentially avoid a plant transient caused by the 1B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) forced shutdown, is reasonable based on the probability of a EFCV line break event and does not represent a significant decrease in safety.

L.5 An allowance is proposed for intermittently opening, under administrative control, closed primary containment isolation valves, other than those currently allowed to be opened using CTS 3.6.3 LCO Footnote ** and Action Footnote *. The allowance is presented in ITS 3.6.1.3 ACTIONS Note 1, and in Note 2 to SR 3.6.1.3.2 and SR 3.6.1.3.3. Opening of primary containment penetrations on an intermittent basis is required for performing surveillances, repairs, routine evolutions, etc. Intermittently opening closed PCIVs is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the PCIV is open and the administrative controls established to ensure the affected penetration can be isolated when a need for primary containment isolation is indicated.

L.6 CTS 4.6.3.1 is proposed to be deleted. Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, ITS SR 3.0.1 requires the appropriate SRs (in this case SR 3.6.1.3.5 and SR 3.6.1.3.7, as applicable) to be performed to demonstrate OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not required and have been deleted from the Technical Specifications.

L.7 Not used. | C

L.8 The phrase "actual or," in reference to the isolation test signal in CTS 4.6.3.2, has been added to proposed SR 3.6.1.3.8, which verifies that each PCIV actuates on an automatic isolation signal. This allows satisfactory automatic PCIV isolations for other than Surveillance purposes to be used to fulfill the Surveillance Requirement. Operability is adequately demonstrated in either case since the PCIV itself cannot discriminate between "actual" or "test" signals.

L.9 The requirement in CTS 4.6.3.4 that each excess flow check valve must check flow has been deleted. Proposed SR 3.6.1.3.9 now requires the EFCVs to actuate to their isolation position (i.e., closed) on an actual or simulated instrument line break signal. The requirements for the EFCVs are provided in 10 CFR 50 Appendix A, GDCs 55 and 56, and as further detailed in Regulatory Guide 1.11. These requirements state that there should be a high degree of assurance that the EFCVs will close or be closed if the instrument line outside containment is lost during normal reactor operation, or under

TECHNICAL CHANGES - LESS RESTRICTIVE

L.9 (cont'd) accident conditions. The Instrument Line Break Analysis in the NMP2 USAR Section 15.6.2 assumes both the EFCV and the manual block valve to be unavailable, i.e., fail to close; the accident is terminated by cooling down the plant. Therefore, since the actual leakage is not an assumption of the accident analysis (the leakage is assumed to be the maximum allowed through the broken line), the leakage limit (i.e., check flow) has been deleted.

L.10 The requirements of CTS 4.6.1.1.b, including footnote b, related to verification of the position of primary containment isolation manual valves and blind flanges, are revised in proposed SR 3.6.1.3.2 and SR 3.6.1.3.3 to exclude verification of manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position. The purpose of CTS 4.6.1.1.b is to ensure that manual primary containment isolation devices that may be misaligned are in the correct position to help ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design and analysis limits. For manual valves or blind flanges that are locked, sealed, or otherwise secured in the correct position, the potential of these devices to be inadvertently misaligned is low. In addition, manual valves and blind flanges that are locked, sealed, or otherwise secured in the correct position are verified to be in the correct position prior to locking, sealing, or securing. As a result of this control of the position of these manual primary containment isolation devices, the periodic Surveillance of these devices in CTS 4.6.1.1.b is not required to help ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is maintained within design and analysis limits. This change also provides the benefit of reduced radiation exposure to plant personnel through the elimination of the requirement to check the position of manual valves and blind flanges, located in radiation areas, that are locked, sealed, or otherwise secured in the correct position.

L.11 CTS 4.6.1.1.b requires verification that certain primary containment penetrations are isolated. An allowance is proposed to allow the verification of the isolation devices used to isolate the penetrations in high radiation areas to be verified by use of administrative means. The allowance is presented in Note 1 to ITS Required Actions A.2 and C.2, SR 3.6.1.3.2, and SR 3.6.1.3.3. This allowance is considered acceptable since access to these areas is typically restricted in MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment once they have been verified to be in the proper position is low. If for some reason these devices are opened (e.g., maintenance), the associated procedure or work package would require their closure after the work is completed. The Required Action or Surveillance may be performed by reviewing that no work was performed in the associated radiation area since the isolation device was closed or if work was performed in

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) the area that closure was verified upon completion of the work if the valve was opened. In addition, an allowance is proposed to allow verification of isolation devices that are locked, sealed, or otherwise secured to also be performed using administrative means. The allowance is presented in Note 2 to ITS Required Actions A.2 and C.2. Plant procedures control the operation of locked, sealed, or otherwise secured isolation devices; thus the potential for inadvertent misalignment of these devices after locking, sealing, or otherwise securing is low. In addition, the isolation devices were verified to be in the correct position prior to locking, sealing, or otherwise securing.

L.12 CTS 3.6.1.2 Action (Restore) c and d requires restoration of the leakage to within limits, but does not provide a finite Completion Time. However, since the leakage rate from the valves is considered in the current definition of PRIMARY CONTAINMENT INTEGRITY (CTS Definition 1.31) the restoration time of the CTS 3.6.1.1 Action, 1 hour, is applicable. In addition, if a purge supply valve with resilient seals is the reason the leakage is not within limits, CTS 3.6.1.7 Action b is required to be entered, and provides 24 hours to restore the leakage to within limits (however, since CTS 3.6.1.1 Action is more limiting, it will govern the total time to restore leakage). The times to restore the leakage (by isolating the penetration with a device that meets the applicable leakage limits) have been modified in the ITS to be 4 hours for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage paths (which includes purge supply valve leakage), excluding MSIVs (ITS 3.6.1.3 Required Action D.1, 1st and 2nd Completion Times), 8 hours for MSIVs (ITS 3.6.1.3 Required Action D.1, 3rd Completion Time), and 72 hours for valves in hydrostatically tested lines on a closed system (ITS 3.6.1.3 Required Action D.1, 4th Completion Time). In addition, the 4 hour and 8 hour times are consistent with the existing times allowed for other conditions when valves in hydrostatically tested lines, secondary containment, or MSIVs are inoperable. With one of the leakages not within limit, the risk associated with continued operation for a short period of time could be less than that associated with a plant shutdown, since the change provides more time to restore the leakage to within limits. This change is acceptable due to the low probability of an event that would require the leakage to be within limits during the short time in which continued operation is allowed with leakage outside the limits. In addition, for the hydrostatically tested lines on a closed system, the valves are either in a closed system as specifically defined in NUREG-0800, section 6.2.4, or are water sealed, and would not be expected to leak after the accident (i.e., a closed system as defined in the USAR). ITS 3.6.1.3 ACTIONS Note 4 will also require immediately taking the ACTIONS of ITS 3.6.1.1 (which reduces the time allowed to restore the leakage to within limits to 1 hour) if leakage results in the overall primary containment leakage rate acceptance criteria being

D

B

B

B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.12 (cont'd) exceeded. Therefore, assurance is provided that the currently listed leakage limits will not adversely impact primary containment Operability during the extended time allowed to restore the leakage.

L.13 The details relating to the Line Description and Termination Region for the potential bypass leakage paths in CTS Table 3.6.1.2-1 are proposed to be deleted. These details are not necessary to ensure the leakage rates through the potential bypass leakage paths are within limits. The requirements of ITS 3.6.1.3 (which require the valves to be Operable), SR 3.6.1.3.11 and SR 3.6.1.3.12 (which requires the leakage rates to be verified within limits), and Table 3.6.1.3-1 (which lists the specific valves and the leakage rate limits) are adequate to ensure the leakage rates are maintained within limits. Therefore, these details have not been included in ITS Table 3.6.1.3-1.

L.14 Not used. | D

L.15 CTS 3.6.1.7 limits the time the 12 inch and 14 inch purge valves can be open to 135 hours per 365 days for PURGING OR VENTING. Footnote * to CTS 3.6.1.7 modifies the restriction to allow the purge valves to be open for an unlimited amount of time for primary containment pressure control, provided 2GTS*AOV101 is closed (which isolates the 20 inch line to the SGT System) and the 2 inch bypass line is the only flow path to the SGT System. The ITS does not include the time limitations, and replaces them with specific criteria for opening. The time limits were based on engineering judgement and/or early plant operating experience, and not based on any analytical requirement. The proposed limits on when the purge valves are permitted to be open, provided in the Note to proposed SR 3.6.1.3.1, will ensure appropriate controls. The Note will continue to allow the purge valves to be open for inerting, deinerting, and pressure control, and will now allow the purge valves to also be open for ALARA or air quality considerations for personnel entry, as well as for Surveillances that require the purge valves to be open. Thus, use of the purge valves will continue to be minimized and limited to safety related reasons. The operating history indicates that these valves are only opened for the specified reasons and for cumulative periods that are generally less than the current allowed cumulative times. In addition, these valves are fully qualified to close in the required time under accident conditions to isolate the affected penetrations.

L.16 The requirement in CTS 3.6.1.7.b and CTS 4.6.1.7.1 to verify the primary containment purge valves with resilient seals are blocked to limit their opening to 60° or 70°, as applicable, has been deleted. The limits on the opening ensure the valves will close during a design basis accident (LOCA) to minimize the radiological consequences to within the limits of 10 CFR 100. These

TECHNICAL CHANGES - LESS RESTRICTIVE

L.16 (cont'd) blocking devices are permanently installed devices located on the actuator and will require a design change to increase or decrease the current limits. The NMPC Design Control Process and Maintenance Program will ensure the blocking devices are set properly, and therefore, a requirement in the Technical Specifications is not necessary. These settings are not affected by drift, and therefore, if set properly there is no reason to expect a change in the settings. If maintenance was performed on the valve and the actuator was disassembled, the installation instructions will require the blocking devices settings to be verified.

L.17 Not used. | D

L.18 The surveillance frequency of CTS 4.6.1.7.2 (the leakage rate test of primary containment purge valves with resilient seals) is proposed to be extended from 92 days to 184 days and once within 92 days after opening the valve in proposed SR 3.6.1.3.6. The current 92 day frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened) and since the valves are opened during the operating cycle for containment pressure control and to comply with the Inservice Test Program. The surveillance test history indicates that the valves normally pass the leakage limit a the current 92 day frequency. Since the failure mechanism of the seal is a result of cycling the valve, there is no additional need to perform the test at the current frequency if the valves are not cycled. Therefore, based on the surveillance test history and the failure mechanism of the resilient seals, the proposed change is adequate to ensure leakage is maintained within the limit.

L.19 CTS 3.6.5.3 Action a.1 requires suspension of PURGING and VENTING (except when the containment purge full flow line to the SGT System is isolated as allowed by Footnote **) within 30 minutes when one SGT subsystem is inoperable and CTS 3.6.5.3 Action b.1 requires suspension of PURGING, VENTING, or pressure control (with no time specified to suspend the operations) when both SGT subsystems are inoperable. In the ITS, the Note to proposed SR 3.6.1.3.1, which allows the purge valves to be open under certain conditions, will include the SGT requirements of CTS 3.6.5.3 Actions a.1 (including Footnote **) and b.1. If the purge valves are open when not allowed by the Note, ITS 3.6.1.3 ACTION B will be required to be entered as the purge valves would be considered inoperable. ACTION B allows 1 hour to isolate the penetration. This proposed 1 hour period is consistent with the existing time allowed for conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various containment degradations. This is acceptable due to the low probability of an event that could pressurize the primary containment during the

TECHNICAL CHANGES - LESS RESTRICTIVE

L.19 (cont'd) short time in which continued operation is allowed with the SGT System inoperable. In addition, the SGT Specification (CTS 3.6.5.3 and ITS 3.6.4.3) would also be requiring the unit to be shut down when both SGT subsystems are inoperable.

<CTS>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC L.3> <3.6.1.7 Act a> B. ---------NOTE--------- Only applicable to penetration flow paths with two PCIVs. [or more] ------------------ One or more penetration flow paths with two PCIVs inoperable [except ~~for purge valve~~ due to leakage not within limit].	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour AND 72 hours for EFCVs and penetrations with a closed system
<3.6.3 Act a> <3.6.3 Act b> <4.6.1.1.b> <DOC L.11> C. ---------NOTE--------- Only applicable to penetration flow paths with only one PCIV. ------------------ One or more penetration flow paths with one PCIV inoperable [except due to leakage not within limit].	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND C.2 ---------NOTE--------- [1.] Isolation devices in high radiation areas may be verified by use of administrative means. [2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means.] [TSTF-269] ------------------ Verify the affected penetration flow path is isolated.	~~4~~ hours [except for excess flow check Valves (EFCVs) and penetrations with a closed system] [TSTF-30 change not shown] Once per 31 days
<3.6.1.2 Act c "with"> <3.6.1.2 Act d "with"> <3.6.1.2 Act c "restore"> <3.6.1.2 Act d "restore"> D. [One or more penetration flow paths with] Secondary containment bypass leakage rate[, MSIV leakage rate, or hydrostatically tested line leakage rate] not within limit.	D.1 ~~Restore leakage rate to within limit.~~ [Insert D.1]	4 hours [for secondary containment bypass leakage] [AND 8 hours for MSIV leakage AND 72 hours for hydrostatically tested line leakage on a closed system] [4 hours for hydrostatically tested line leakage not on a closed system AND]

Insert D.2 and D.3

(continued)

20 INSERT D.1

D.1 -------------------NOTE-------------------
The isolation device used to satisfy Required Action D.1 shall have been verified to meet the applicable leakage rate limit of the inoperable valve.

Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.

INSERT D.2 and D.3

AND 20 D.2 -------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. -- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment AND Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment
AND 16 D.3 Perform SR 3.6.1.3.6 for the resilient seal purge supply valves closed to comply with Required Action D.1.	Once per 92 days

D

16. (continued)

they must be restored in 4 hours, consistent with other secondary containment bypass leakage path valves. In addition, due to this change, ISTS Required Action E.3 has also been modified to pertain to purge exhaust valves only. However, since the CTS requires the 92 day test on purge supply valve leakage if one of the purge supply valves with resilient seals is used to isolate the penetration, the 92 day test has been added as Required Action D.3. D

17. The words in ISTS Conditions A and B Notes and the words in ISTS Condition B have been modified to state "two or more" in lieu of "two." Some penetration flow paths at NMP2 have more than two PCIVs. This was required by the NRC for some penetrations whose outside PCIV was not close enough to the primary containment. This change will ensure an LCO 3.0.3 entry is not required for this design and the appropriate actions are taken consistent with a plant with only two PCIVs per penetration flow path. This change is also consistent with proposed TSTF-207, Rev. 3 (It is noted that the BWR/6 ISTS markup provided in TSTF-207, Rev. 3 inadvertently left out the words "or more" in Condition B. The BWR/4 ISTS markup included these words in Condition B.) C

18. The leakage limit and test pressure for ISTS SR 3.6.1.3.11 (ITS SR 3.6.1.3.13) have been deleted from the Technical Specification Surveillance based on an NRC Request for Additional Information comment provided in an NRC letter dated 5/10/99. The leakage limit and test pressure are now located in the ITS Bases. This is also consistent with proposed TSTF-52, Revision 2. C

19. The LCO statement has been modified since not all valves in secondary containment bypass leakage pathways are PCIVs (valves 2CMS*SOV74A, 74B, 75A, 75B, 76A, 76B, 77A, and 77B are not PCIVs). C

20. The NMP2 secondary containment bypass leakage limit requirements are not on a "combined" basis, as shown in ISTS SR 3.6.1.3.9, but on a "per valve" basis (ITS SR 3.6.1.3.11). ISTS 3.6.1.3 Required Action D.1 requires the leakage rate to be restored to within the limit and describes in the Bases that this can be performed by isolating the affected penetration flow path. Once isolated, the Bases further describes that the leakage rate for the penetration is the leakage rate through the closed valve. Also, once isolated, ISTS SR 3.6.1.3.9 is satisfied since the leakage rate limits are on a "combined" basis. Therefore, with the penetration isolated, which results in the ISTS SR 3.6.1.3.9 requirements being met, the leakage has been restored to within limits as required by the ISTS 3.6.1.3 Required Action D.1, the LCO requirements are being met, and ISTS 3.6.1.3 Condition D can be exited. With the NMP2 secondary containment bypass leakage limit requirements on a "per valve" basis, the ITS SR 3.6.1.3.11 requirements are not met even when the affected penetration flow path is isolated. Thus, the ISTS 3.6.1.3 Required Action D.1 action to restore the leakage rate to within limit, with a Bases description that states isolating D

20. (continued)

the affected penetration flow restores the leakage to within the limit is not appropriate, since isolating the penetration does not restore the leakage rate of the inoperable valve to within its limits. Therefore, Required Action D.1 has been modified to require isolation of the affected penetration flow path, similar to the requirements specified in ISTS 3.6.1.3 Required Actions B.1 and C.1. Also, a Note has been added to ensure that the isolation device used to meet Required Action D.1 meets the appropriate leakage rate requirement for the valve it is replacing. This Note is similar to the Note for ISTS 3.4.6 Required Actions A.1 and A.2, whose purpose is similar. In addition, while ACTION D is the ACTION to enter when hydrostatically tested line or MSIV leakage rates are not within limits, requiring isolation of the affected penetration in lieu of restoring the leakage is acceptable since this is how the ISTS "restore" requirement is met, as described in the Bases. D

In addition, Required Action D.2 has also been added to periodically ensure the penetration is isolated, consistent with the requirements of similar Required Actions in ISTS 3.6.1.3 ACTIONS A and C.

BASES

ACTIONS

C.1 and C.2 (continued)

specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by a Note that applies to ~~valves and blind flanges~~ located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of ~~these valves~~, once they have been verified to be in the proper position, is low.

two Notes TSTF-269

isolation devices 12

Insert C.1 and C.2 TSTF-269

D.1, D.2, and D.3 (SR 3.6.1.3.11)

MSIV leakage rate (SR 3.6.1.3.12) or hydrostatically tested line leakage rate (SR 3.6.1.3.13)

With the secondary containment bypass leakage rate not within limit, the assumptions of the safety analysis are not met. ~~Therefore, the leakage must be restored to within limit within 4 hours.~~ Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a the 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 and the relative importance of secondary containment bypass leakage to the overall containment function.

may be 13

Insert D.1a

for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage

Insert D.1b

Insert D.1c

E.1, E.2, and E.3

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by 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

exhaust 7

(continued)

TSTF-269 INSERT C.1 and C.2

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.

15 INSERT D.1a B

Therefore, the leakage rate must be restored to within limit or the affected penetration flow path must be isolated within the Completion Times appropriate for each type of valve leakage: a) hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage are required to be restored within 4 hours; b) MSIV leakage is required to be restored within 8 hours; and c) hydrostatically tested line leakage on a closed system is required to be restored within 72 hours. 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 B D

15 INSERT D.1b

Required Action D.1 is modified by a Note stating that the isolation device used to satisfy the Required Action must meet the same leakage rate requirements as the inoperable valve. Thus, D

15 INSERT D.1c D

The Completion Time of 8 hours for MSIV leakage allows a period of time to restore the MSIV leakage and is acceptable given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is acceptable based on the available water seal expected to remain as a gaseous fission product boundary during the accident and, in many cases, the associated closed system. The closed system must meet the requirements of Ref. 6. B B

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no 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 valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, 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. D

15 INSERT D.1c (continued)

Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified 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 once they have been verified to be in the proper position, is low. D

For the containment purge supply valve with resilient seal that is closed in accordance with Required Action D.1, SR 3.6.1.3.6 must be performed at least once every 92 days, as required by D.3. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge supply valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

INSERT BWR/4 ISTS B 3.6.1.8
(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.~~8~~.2 (continued)

additional assurance that the vacuum breakers are OPERABLE, since they are located in a harsh environment (the suppression chamber airspace). In addition, this functional test is required within 12 hours after ~~either a discharge of steam to the suppression chamber from the safety/relief valves or after an operation that causes any of the vacuum breakers to open.~~

SR 3.6.1.~~8~~.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker ~~full~~ open differential pressure of ~~[0.5]~~ ≤ 0.25 psid is valid. The ~~[18]~~ 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. ~~For this facility~~, the ~~[18]~~ 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

ing (i.e., starts to open from the fully closed position)

REFERENCES

1. ~~F~~SAR, Section ~~[~~6.2~~]~~.1.

2. 10 CFR 50.36 (c) (2) (ii).

Insert Page B 3.6-47g

L.14 CHANGE

Not used.

D

L.17 CHANGE

Not used.

L.18 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change will allow the leakage rate test of primary containment purge valves with resilient seals be extended from 92 days to 184 days and once within 92 days after opening the valve. Since primary containment purge penetrations are not assumed to be initiators of any design basis accident or transient, this change will not significantly increase the probability of any previously analyzed accident. Since the intent of the change ensures that the leakage is maintained within the proper limits, the consequences of any analyzed event will be bounded by the current accident analyses. Therefore, this change does not significantly increase the consequences of any previously analyzed accident.

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

   This change does not result in any changes to the equipment design or capabilities or to the operation of the plant. Further, since the change impacts only the frequency of verification and does not result in any change in the response of the equipment to an accident, the change does not create the possibility of a new or different kind of accident from any previously analyzed accident.

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

   This change continues to ensure the leakage past the primary containment purge resilient seals is maintained within limits. Therefore, this change does not involve a significant reduction in a margin of safety.

L.19 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change would allow additional time to suspend venting, purging, and pressure control if one or both SGT subsystems are inoperable. Venting, purging, and pressure control with inoperable SGT subsystems is not considered as an initiator of any previously analyzed accident. Therefore, this change does not significantly increase the probability of such accidents. The proposed change allows additional temporary operation with less than the required SGT System capability. However, the consequences of an event that may occur during the extended outage time would not be any different than during the currently allowed outage time for other loss of containment integrity situations. Therefore, this change does not significantly increase the consequences of any previously analyzed accident.

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

   This change does not result in any changes to the equipment design or capabilities or to the operation of the plant. Further, since the change impacts only the Required Action Completion Time for the system and does not result in any change in the response of the equipment to an accident, the change does not create the possibility of a new or different kind of accident from any previously analyzed accident.

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

   This change impacts only the Required Action Completion Time to suspend venting, purging, and pressure control when one or both SGT subsystems are inoperable. The methodology and limits of the accident analysis are not affected, nor is the primary containment response. Therefore, the change does not involve a significant reduction in the margin of safety.

Specification 5.5

A.1

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITIONS FOR OPERATION

3.6.1.2 (Continued)

ACTION:

b. The measured combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, ~~except for main steam line isolation valves* and valves which are hydrostatically leak tested,~~ ~~subject to Type B and C tests~~ equaling or exceeding 0.60 La, or A.8

c. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, or

d. The measured leakage rate through any valve that is part of a potential bypass leakage pathway exceeding the limit specified in Table 3.6.1.2-1

Restore: 5.5.12.d.1

a. The overall integrated leakage rate to less than 1.0 La, and

b. The combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steamline isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests to less than 0.60 La, and 5.5.12.d.1

c. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves, and

d. The leakage rate to less than or equal to that specified in Table 3.6.1.2-1 for any valve that is part of a potential bypass leakage path. Alternatively, in lieu of restoring the inoperable valve to OPERABLE status, isolate the affected bypass leakage path by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. The isolation device must meet the leakage limit of Table 3.6.1.2-1 associated with the inoperable valve. Enter applicable ACTION statement(s) for system(s) made inoperable by isolating a bypass leakage path. D

(See Discussion of Changes for ITS:3.6.1.1, in Section 3.6.)

A.8

~~* Exemption to Appendix J to 10 CFR 50.~~