UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

March 22, 1991

Docket No. 50-260

Mr. Dan A. Nauman
Senior Vice President, Nuclear Power
Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, Tennessee 37402-2801

Dear Mr. Nauman:

SUBJECT: ISSUANCE OF AMENDMENT AND COMPLIANCE REVIEW OF 10 CFR 50 APPENDIX J AND TMI ITEM II.E.4.2.1-4 (TAC NOS. 00081 AND 74609) (TS 251)

The Commission has issued the enclosed Amendment No. 193, to Facility Operating License No. DPR-52 for the Browns Ferry Nuclear (BFN) Plant, Unit 2. This amendment is in response to your application dated August 2, 1988, as clarified by letter dated July 13, 1989, to update Table 3.7.A, "Primary Containment Isolation Valves," of the Technical Specifications (TS). The updates to Table 3.7.A and the BFN Appendix J program reflect changes due to plant modifications. The revised table conforms to the Unit 2 configuration and is therefore acceptable. A similar review will be required for Units 1 and 3 prior to accepting their respective TS tables for restart. A copy of the Safety Evaluation (SE) is enclosed. Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

The staff also reviewed the Browns Ferry (BFN), Unit 2, primary containment isolation arrangement for compliance with TMI Action Item II.E.4.2, Parts 1-4, "Containment Isolation Dependability." The staff's SE concluded that TVA identified each containment system at BFN, Unit 2, as essential or non-essential, assured that all essential systems were remote-manually operated and the non-essential systems met the intent of isolation requirements specified in the General Design Criteria of 10 CFR Part 50, Appendix A. Furthermore, the staff reviewed TVA's Appendix J program for applicable containment isolation valves, except as noted in the SE. Local Leak Rate Tests (LLRT) conducted at BFN were determined to be in accordance with Appendix J requirements and therefore acceptable. A similar review will also be performed for Units 1 and 3.

Throughout the enclosed SE, the staff made frequent references to a number of commitments by TVA, particularly those in response to staff recommendations documented in a letter dated August 17, 1990. If we have mis-stated any TVA commitment, you are requested to notify the NRC within 30 days after receipt of this letter.

Sincerely,

Original signed by

Thierry M. Ross, Project Manager
Project Directorate II-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No.193 to
   License No. DPR-52
2. Safety Evaluation

cc w/enclosures:
See next page

Subject to comments in 3/15/91 note to T. Ross

OFC	PDII-4/LA	PDII-4/PE	PDII-4/PM	SPLB	OGC
NAME	MKrebs MK	DMonarkas/dw	TRoss TR	CMcCracken	E Hollor
DATE	3/14/91	3/14/91	3/14/91	3/21/91	3/15/91
OFC	PDII-4/DD	PDII-4/D			
NAME	SBlack	FHebdon			
DATE	3/22/91	3/22/91			

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AMENDMENT NO. 193 FOR BROWNS FERRY UNIT 2 - DOCKET NO. 50-260
DATED: March 22, 1991

Docket File	
NRC PDR	
Local PDR	
BFN Reading File	
S. Varga	14-E-4
G. Lainas	14-H-3
F. Hebdon	
S. Black	
M. Krebs	
T. Ross	
J. Williams	
D. Moran	
B. Wilson	RII
P. Kellogg	RII
OGC	15-B-13
D. Hagan	MNBB-3302
E. Jordan	MNBB-3302
G. Hill	P1-130
Wanda Jones	MNBB-7103
J. Calvo	11-F-22
ACRS(10)	
GPA/PA	2-G-5
OC/LFMB	MNBB-9112
J. Kudrick	8-D-22

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-260

BROWNS FERRY NUCLEAR PLANT, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 193
License No. DPR-52

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Tennessee Valley Authority (the licensee) dated August 2, 1988 and as clarified by letter of July 13, 1989, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. DPR-52 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 193, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Frederick J. Hebdon

Frederick J. Hebdon, Director Project Directorate II-4, NRR
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: March 22, 1991

ATTACHMENT TO LICENSE AMENDMENT NO. 193

FACILITY OPERATING LICENSE NO. DPR-52

DOCKET NO. 50-260

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4.7.A. Primary Containment

4.7.A.2.g (Cont'd)

The total path leakage from all penetrations and isolation valves shall not exceed 60 percent of L_a per 24 hours. Leakage from containment isolation valves that terminate below suppression pool water level may be excluded from the total leakage provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54.6 psig. Leakage from containment isolation valves that are in closed-loop, seismic class I lines that will be water sealed during a DBA will be measured but will be excluded when computing the total leakage.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS

4.7.A. Primary Containment

4.7.A.2. (Cont'd)

h. (1) If at any time it is determined that the criterion of 4.7.A.2.g is exceeded, repairs shall be initiated immediately.

(2) If conformance to the criterion of 4.7.A.2.g is not demonstrated within 48 hours following detection of excessive local leakage, the reactor shall be shut down and depressurized until repairs are effected and the local leakage meets the acceptance criterion as demonstrated by retest.

i. The main steamline isolation valves shall be tested at a pressure of 25 psig for leakage during each refueling outage. If the leakage rate of 11.5 scf/hr for any one main steamline isolation valve is exceeded, repairs and retest shall be performed to correct the condition.

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
1	Main steamline isolation valves (FCV-1-14, -26, -37, & -51; 1-15, -27, -38, & -52)	4	4	$3 < T < 5$	0	GC	7
1	Main steamline drain isolation valves (FCV-1-55 & 1-56)	1	1	15	0	GC	1
1*	Reactor water sample line isolation valves (FCV-43-13, -14)	1	1	5	C	SC	1
2	RHRS shutdown cooling supply isolation valves (FCV-74-48 & -47)	1	1	40	C	SC	1
2	RHRS - LPCI to reactor (FCV-74-53 & -67)		2	40	C	SC	3
2	Suppression chamber drain (FCV-75-57 & -58)		2	15	0**	GC	2
2	Drywell equipment drain discharge isolation valves (FCV-77-15A & -15B)		2	15	0	GC	1
2	Drywell floor drain discharge isolation valves (FCV-77-2A & -2B)		2	15	0	GC	1

*These valves isolate only on reactor vessel low low low water level (≥398") and main steam line high radiation of Group 1 isolations.

**These valves are normally open when the pressure suppression head tank is aligned to serve the RHR and CS discharge piping and closed when the condensate head tank is used to serve the RHR and CS discharge piping. (See Specification 3.5.H)

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
3	Reactor water cleanup system supply isolation valves (FCV-69-1, & -2)	1	1	30	0	GC	1
4	HPCI warm-up (FCV-73-81)		1	10	C	SC	1
4	HPCIS steamline isolation valves (FCV-73-2 & -3)	1	1	20	0	GC	1
5	RCICS steamline isolation valves (FCV-71-2 & -3)	1	1	15	0	GC	1
6	Drywell nitrogen make-up inlet isolation valves (FCV-76-18)		1	5	C	SC	1
6	Suppression chamber nitrogen make-up inlet isolation valves (FCV-76-19)		1	5	C	SC	1
6	Drywell main exhaust isolation valves (FCV-64-29 & -30)		2	2.5	C	SC	1
6	Suppression chamber main exhaust isolation valves (FCV-64-32 & -33)		2	2.5	C	SC	1
6	Drywell/suppression chamber purge inlet (FCV-64-17)		1	2.5	C	SC	1
6	Drywell purge inlet (FCV-64-18)		1	2.5	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (Sec.)	Normal Position	Action on Initiating Signal	Notes
6	Torus hydrogen sample line valves - Analyzer A (FSV-76-55 & -56)		2	N/A	O/C	GC/SC	6, 1
6	Drywell hydrogen sample line valves - Analyzer A (FSV-76-49 & -50)		2	N/A	O/C	GC/SC	6, 1
6	Sample return valves - Analyzer A (FSV-76-57 & -58)		2	N/A	0	GC	1
6	Torus hydrogen sample line valves - Analyzer B (FSV-76-65 & -66)		2	N/A	O/C	GC/SC	6, 1
6	Drywell hydrogen sample line valves - Analyzer B (FSV-76-59 & -60)		2	N/A	O/C	GC/SC	6, 1
6	Sample return valves - Analyzer B (FSV-76-67 & -68)		2	N/A	0	GC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
6	Suppression chamber purge inlet (FCV-64-19)		1	2.5	C	SC	1
6	Drywell/suppression chamber nitrogen make-up inlet (FCV-76-17)		1	5	C	SC	1
6	Drywell exhaust valve bypass to standby gas treatment system (FCV-64-31)		1	5	0	GC	1
6	Suppression chamber exhaust valve bypass to standby gas treatment system (FCV-64-34)		1	5	0	GC	1
6	System suction isolation valves to air compressors "A" and "B" (FCV-32-62 & -63)		2	15	0	GC	1
8	TIP guide tubes (5) (FCV-94-501, -502, -503, -504, & -505)		1 per guide tube	N/A	C	GC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Standby liquid control system check valves (CV 63-526 & -525)	1	1	NA	C	Process	1
N/A	Feedwater check valves (CV-3-558, -572, -554 & -568)	2	2	NA	0	Process	1
N/A	Control rod hydraulic return check valves (CV-85-576)		1	N/A	0	Process	1
N/A	RHRS - LPCI to reactor check valves (CV-74-54 & -68)	2		N/A	C	Process	3
N/A	CAD system torus/drywell exhaust to standby gas treatment (FCV-84-19)		1	N/A	C	SC	1
6	Drywell/suppression chamber nitrogen Purge Inlet (FCV-76-24)		1	5	C	SC	1
N/A	Core spray discharge to reactor check valves (FCV-75-26 & -54)	2		N/A	C	Process	3
6	Drywell dP air compressor suction valve (FCV-64-139)		1	10	C	SC	1
6	Drywell dP air compressor discharge valve (FCV-64-140)		1	10	C	SC	1
6	Drywell CAM suction valves (FCV-90-254A & -254B)		2	10	0	GC	1
6	Drywell CAM discharge valves (FCV-90-257A & -257B)		2	10	0	GC	1
6	Drywell CAM suction valve (FCV-90-255)		1	10	0	GC	1
6	CAD system torus/drywell exhaust to standby gas treatment (FCV-84-20)		1	10	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Core spray discharge to reactor isolation valves (75-25 & -53)		2	N/A	C	SC	3
N/A	PSC return line check valves (12-738 & -741)		2	N/A	C	N/A	2
N/A	Suppression chamber sample RHR pumps A&C isolation valves (43-28A & -28B)		2	N/A	C	SC	2
N/A	Suppression chamber sample RHR pumps B&D isolation valves (43-29A & -29B)		2	N/A	C	SC	2
N/A	PSC head tank tie-in to RHR check valves (74-803, -804, -792 & -802)		4	N/A	O	Process	3
N/A	PSC head tank tie-in to CS check valves (75-606, -609, -607 & -610)		4	N/A	O	Process	3
N/A	TIP nitrogen purge check valve (76-653)		1	N/A	C	Process	1
N/A	CAD crosstie to DW control air check valve (84-617)		1	N/A	C	Process	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	HPCI turbine exhaust drain check valves (73-24 & -609)		2	N/A	C	Process	2
N/A	RCIC turbine exhaust check (71-14 & -580)		2	N/A	C	Process	1
N/A	RCIC vacuum pump discharge check valves (71-32 & -592)		2	N/A	C	Process	2
N/A	RHR suppression chamber spray isolation valves (74-58, -72, -57 & -71)		4	N/A	C	SC	3
N/A	RHR drywell spray isolation valves (74-61, -75, -60, & -74)		4	N/A	C	Process	3
N/A	RHR shutdown cooling supply bypass check valves (74-661/662)	2		N/A	C	Process	1, 5
N/A	Suppression chamber drain isolation valve (74-722)		1	N/A	C	SC	2, 4
N/A	CAD admission check valves to DW (84-600 & -602)		2	N/A	C	Process	1
N/A	CAD admission check valves to suppression chamber (84-601 & -603)		2	N/A	C	Process	1
N/A	CAD admission isolation valves to DW (84-8A & -8D)		2	N/A	C	SC	1
N/A	CAD admission isolation valves to suppression chamber (84-8B & -8C)		2	N/A	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Reactor building closed cooling water drywell supply check valve valve (70-506)		1	N/A	O	Process	1
N/A	RCICS pump suction isolation valves (71-17 & -18)		2	N/A	C	SC	2
N/A	RCICS pump minimum flow bypass isolation valve (71-34)		1	N/A	C	SC	2
N/A	RCICS pump discharge check valve valves (71-40)		1	N/A	C	Process	1
N/A	RCICS pump minimum flow bypass check valve (71-57)		1	N/A	C	Process	2
4	HPCI pump suction isolation valves (73-26 & -27)		2	80 sec.	C	SC	2
N/A	HPCI pump minimum flow bypass isolation valve (73-30)		1	N/A	C	SC	2
N/A	HPCI pump discharge check valve (73-45)		1	N/A	C	Process	1
N/A	HPCI pump minimum flow bypass check valve (73-559)		1	N/A	C	Process	2
N/A	HPCI turbine exhaust check valves (73-23 & -603)		2	N/A	C	Process	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Demineralized water supply check valve (2-1192)		1	N/A	C	N/A	1
N/A	Demineralized water supply isolation valve (2-1383)		1	N/A	C	N/A	1, 4
N/A	Service air supply isolation valves (33-1070)		1	N/A	C	N/A	1
N/A	Service air supply check valve (33-785)		1	N/A	C	N/A	1, 4
N/A	Drywell control air inlet header check valves (32-2163 & -336)	1	1	N/A	0	Process	1
N/A	Suppression chamber vacuum relief (64-20 & -21)		2	N/A	C	N/A	1
N/A	Suppression chamber vacuum relief check valves (64-800 & -801)		2	N/A	C	Process	1
N/A	Recirculation pump A seal injection check valves (68-508 & -550)	1	1	N/A	0	Process	1
N/A	Recirculation pump B seal injection check valves (68-523 & -555)	1	1	N/A	0	Process	1
N/A	Reactor water cleanup system discharge check valve (69-579)		1	N/A	0	Process	1
N/A	Reactor building closed cooling water drywell return isolation valve (70-47)		1	N/A	0	GC	1, 4

NOTES FOR TABLE 3.7.A

Key: 0 = Open
C = Closed
SC = Stays Closed
GC = Goes Closed

Note: Isolation groupings are as follows:

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

1. Reactor Vessel Low Low Low Water Level ($\geq$ 398")
2. Main Steamline High Radiation
3. Main Steamline High Flow
4. Main Steamline Space High Temperature
5. Main Steamline Low Pressure

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

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure

Group 3: The valves in Group 3 are actuated by any of the following conditions:

1. Reactor Low Water Level (538")
2. Reactor Water Cleanup (RWCU) System High Temperature in the main steam valve vault,
3. RWCU System High Temperature in RWCU pump room 2A,
4. RWCU System High Temperature in the RWCU pump room 2B,
5. RWCU System High Temperature in RWCU heat exchanger room,
6. RWCU System High Temperature in the space near the pipe trench containing RWCU piping.

Group 4: The valves in Group 4 are actuated by any of the following conditions:

1. HPCI Steamline Space High Temperature
2. HPCI Steamline High Flow
3. HPCI Steamline Low Pressure
4. HPCI Turbine Exhaust Diaphragm High Pressure

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

1. RCIC Steamline Space High Temperature
2. RCIC Steamline High Flow
3. RCIC Steamline Low Pressure
4. RCIC Turbine Exhaust Diaphragm High Pressure

NOTES FOR TABLE 3.7.A (Continued)

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

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure
3. Reactor Building Ventilation High Radiation

Group 7: (Deleted)

Group 8: The valves in Group 8 are automatically actuated by only the following conditions:

1. High Drywell Pressure
2. Reactor Vessel Low Water Level (538")

Note 1: Primary containment isolation valve(s) requiring LLRT at not less than 49.6 psig.

Note 2: Primary containment isolation valve(s) which may be LLRT with water and not included in the 60-percent L_a tabulation, provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54.6 psig.

Note 3: Primary containment isolation valves that are in closed loop, seismic Class 1 lines that will be water sealed during a DBA. These valves will be tested but not included in the 60-percent L_a tabulation.

Note 4: Primary containment isolation valves that are manually operated.

Note 5: Primary containment isolation valves 74-661/662 are considered as a single containment boundary and LLRT as such.

Note 6: Analyzers are such that one is sampling drywell hydrogen and oxygen (valves from drywell open, valves from torus close), while the other is sampling torus hydrogen and oxygen (valves from torus open, valves from drywell close).

Note 7: Primary containment isolation valves requiring LLRT at not less than 25-psig.

3.7.A & 4.7.A Primary Containment

The integrity of the primary containment and operation of the core standby cooling system in combination, ensure that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

During initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required, there will be no pressure on the system thus greatly reducing the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedures will be in effect to minimize the probability of an accident occurring.

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure of 49.6 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates are consistent with the requirements of Appendix J of 10 CFR Part 50 (type A, B, and C tests).

The pressure suppression pool water provides the heat sink for the reactor primary system energy release following a postulated rupture of the system. The pressure suppression chamber water volume must absorb the associated decay and structural sensible heat release during primary system blowdown from 1,035 psig. Since all of the gases in the drywell are purged into the pressure suppression chamber air space during a loss of coolant accident, the pressure resulting from isothermal compression plus the vapor pressure of the liquid must not exceed 62 psig, the suppression chamber maximum pressure. The design volume of the suppression chamber (water and air) was obtained by considering that the total volume of reactor coolant to be condensed is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water levels given in the specification, containment pressure during the design basis accident is approximately 49 psig, which is below the maximum of 62 psig. The maximum water level indications of -1 inch corresponds to a downcomer submergence of three feet seven inches and a water volume of 127,800 cubic feet with or 128,700 cubic feet without the drywell-suppression chamber differential pressure control. The minimum water level indication of -6.25 inches with differential pressure control and -7.25 inches without differential pressure control corresponds to a downcomer submergence of approximately three feet and a water volume of approximately 123,000 cubic feet.

Maintaining the water level between these levels will ensure that the torus water volume and downcomer submergence are within the aforementioned limits during normal plant operation. Alarms, adjusted for instrument error, will notify the operator when the limits of the torus water level are approached.

The maximum permissible bulk pool temperature is limited by the potential for stable and complete condensation of steam discharged from safety relief valves and adequate core spray pump net positive suction head. At reactor vessel pressures above approximately 555 psig, the bulk pool temperature shall not exceed 180°F. At pressures below approximately 240 psig, the bulk temperature may be as much as 184°F. At intermediate pressures, linear interpolation of the bulk temperature is permitted.

They also represent the bounding upper limits that are used in suppression pool temperature response analyses for safety relief valve discharge and loss-of-coolant accident (LOCA) cases. The actions required by Specifications 3.7.C. - 3.7.F. assure the reactor can be depressurized in a timely manner to avoid exceeding the maximum bulk suppression pool water limits. Furthermore, the 184°F limit provides that adequate RHR and core spray pump NPSH will be available without dependency on containment overpressure.

Should it be necessary to drain the suppression chamber, this should only be done when there is no requirement for core standby cooling systems operability. Under full power operation conditions, blowdown from an initial suppression chamber water temperature of 95°F results in a peak long term water temperature which is sufficient for complete condensation.

Limiting suppression pool temperature to 105°F during RCIC, HPCI, or relief valve operation when decay heat and stored energy is removed from the primary system by discharging reactor steam directly to the suppression chamber ensures adequate margin for controlled blowdown anytime during RCIC operation and ensures margin for complete condensation of steam from the design basis LOCA.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a relief valve inadvertently opens or sticks open. This action would include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling heat exchangers, (3) initiate reactor shutdown, and (4) if other relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open relief valve to assure mixing and uniformity of energy insertion to the pool.

If a LOCA were to occur when the reactor water temperature is below approximately 330°F, the containment pressure will not exceed the 62 psig code permissible pressures even if no condensation were to occur. The maximum allowable pool temperature, whenever the reactor is above 212°F, shall be governed by this specification. Thus, specifying water volume-temperature requirements applicable for reactor-water temperature above 212°F provides additional margin above that available at 330°F.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed ("Torus Support System and Attached Piping Analysis for the Browns Ferry Nuclear Plant Units 1, 2, and 3," dated September 9, 1976 and supplemented October 12, 1976) which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system and attached piping. The maintenance of a drywell-suppression chamber differential pressure of 1.1 psid and a suppression chamber water level corresponding to a downcomer submergence range of 3.06 feet to 3.58 feet will assure the integrity of the suppression chamber when subjected to post-loss-of-coolant suppression pool hydrodynamic forces.

Inerting

The relativity small containment volume inherent in the GE-BWR pressure suppression containment and the large amount of zirconium in the core are such that the occurrence of a very limited (a-percent or so) reaction of the zirconium and steam during a LOCA could lead to the liberation of hydrogen combined with an air atmosphere to result in a flammable concentration in the containment. If a sufficient amount of hydrogen is generated and oxygen is available in stoichiometric quantities the subsequent ignition of the hydrogen in rapid recombination rate could lead to failure of the containment to maintain a low leakage integrity. The <4 percent hydrogen concentration minimizes the possibility of hydrogen combustion following a LOCA.

The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is much more probable than the occurrence of the LOCA upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure. The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration.

To ensure that the hydrogen concentration is maintained less than 4 percent following an accident, liquid nitrogen is maintained onsite for containment atmosphere dilution. About 2,260 gallons would be sufficient as a seven-day supply, and replenishment facilities can deliver liquid nitrogen to the site within one day; therefore, a requirement of 2,500 gallons is conservative. Following a LOCA the Containment Air Monitoring (CAM) System continuously monitors the hydrogen concentration of the containment volume. Two independent systems (a system consists of one hydrogen sensing circuit) are installed in the drywell and the torus. Each sensor and associated circuit is periodically checked by a calibration gas to verify operation. Failure of one system does not reduce the ability to monitor system atmosphere as a second independent and redundant system will still be operable.

In terms of separability, redundancy for a failure of the torus system is based upon at least one operable drywell system. The drywell hydrogen concentration can be used to limit the torus hydrogen concentration during post-LOCA conditions. Post-LOCA calculations show that the CAD system initiated within two-hours at a flow rate of 100 scfm will limit the peak drywell and wetwell hydrogen concentration to 3.6-percent (at 4 hours) and 3.8-percent (at 32 hours), respectively. This is based upon purge initiation after 20 hours at a flow rate of 100 scfm to maintain containment pressure below 30 psig. Thus, peak torus hydrogen concentration can be controlled below 4.0 percent using either the direct torus hydrogen monitoring system or the drywell hydrogen monitoring system with appropriate conservatism (≤ 3.8-percent), as a guide for CAD/Purge operations.

Vacuum Relief

The purpose of the vacuum relief valves is to equalize the pressure between the drywell and suppression chamber and reactor building so that the structural integrity of the containment is maintained. The vacuum relief system from the pressure suppression chamber to reactor building consists of two 100-percent vacuum relief breakers (two parallel sets of two valves in series). Operation of either system will maintain the pressure differential less than 2 psig; the external design pressure. One reactor building vacuum breaker may be out of service for repairs for a period of seven days. If repairs cannot be completed within seven days, the reactor coolant system is brought to a condition where vacuum relief is no longer required.

When a drywell-suppression chamber vacuum breaker valve is exercised through an opening-closing cycle the position indicating lights in the control room are designed to function as specified below:

Initial and Final Condition	Check - On	(Fully Closed)
	Green - On	
	Red - Off	
Opening Cycle	Check - Off	(Cracked Open)
	Green - Off	(> 80° Open)
	Red - On	(> 3° Open)
Closing Cycle	Check - On	(Fully Closed)
	Green - On	(< 80° Open)
	Red - Off	(< 3° Open)

The valve position indicating lights consist of one check light on the check light panel which confirms full closure, one green light next to the hand switch which confirms 80° of full opening and one red light next to the hand switch which confirms "near closure" (within 3° of full closure). Each light is on a separate switch. If the check light circuit is operable when the valve is exercised by its air operator there exists a confirmation that the valve will fully close. If the red light circuit is operable, there exists a confirmation that the valve will at least "nearly close" (within 3° of full closure). The green light circuit confirms the valve will fully open. If none of the lights change indication during the cycle, the air operator must be inoperable or the valve disc is stuck. For this case, a check light on and red light off confirms the disc is in a nearly closed position even if one of the indications is in error. Although the valve may be inoperable for full closure, it does not constitute a safety threat.

If the red light circuit alone is inoperable, the valve shall still be considered fully operable. If the green and red or the green light circuit alone is inoperable the valve shall be considered inoperable for opening. If the check and green or check light circuit alone is inoperable, the valve shall be considered inoperable for full closure. If the red and check light circuits are inoperable the valve shall be considered inoperable and open greater than 3°. For a light circuit to be considered operable the light must go on and off in proper sequence during the opening-closing cycle. If none of the lights change indication during the cycle, the valve shall be considered inoperable and open unless the check light stays on and the red light stays off in which case the valve shall be considered inoperable for opening.

The 12 drywell vacuum breaker valves which connect the suppression chamber and drywell are sized on the basis of the Bodega pressure suppression system tests. Ten operable to open vacuum breaker valves (18-inch) selected on this test basis and confirmed by the green lights are adequate to limit the pressure differential between the suppression chamber and drywell during postaccident drywell cooling operations to a value which is within suppression system design values.

The containment design has been examined to determine that a leakage equivalent to one drywell vacuum breaker opened to no more than a nominal 3° as confirmed by the red light is acceptable.

On this basis an indefinite allowable repair time for an inoperable red light circuit on any valve or an inoperable check and green or check light circuit alone or a malfunction of the operator or disc (if nearly closed) on one valve, or an inoperable green and red or green light circuit alone on two valves is justified.

During each operating cycle, a leak rate test shall be performed to verify that significant leakage flow paths do not exist between the drywell and suppression chamber. The drywell pressure will be increased by at least one psi with respect to the suppression chamber pressure and held constant. The two psig setpoint will not be exceeded. The subsequent suppression chamber pressure transient (if any) will be monitored with a sensitive pressure gauge. If the drywell pressure cannot be increased by one psi over the suppression chamber pressure it would be because a significant leakage path exists; in this event the leakage source will be identified and eliminated before power operation is resumed.

With a differential pressure of greater than one psig, the rate of change of the suppression chamber pressure must not exceed 0.25 inches of water per minute as measured over a 10-minute period, which corresponds to about 0.09 lb/sec of containment air. In the event the rate of change exceeds this value then the source of leakage will be identified and eliminated before power operation is resumed.

The water in the suppression chamber is used for cooling in the event of an accident; i.e., it is not used for normal operation; therefore, a daily check of the temperature and volume is adequate to assure that adequate heat removal capability is present.

The interior surfaces of the drywell and suppression chamber are coated as necessary to provide corrosion protection and to provide a more easily decontaminable surface. The surveillance inspection of the internal surfaces each operating cycle assures timely detection of corrosion. Dropping the torus water level to one foot below the normal operating level enables an inspection of the suppression chamber where problems would first begin to show.

The primary containment preoperational test pressures are based upon the calculated primary containment pressure response in the event of a LOCA. The peak drywell pressure would be about 49 psig which would rapidly reduce to less than 30 psig within 20 seconds following the pipe break. Following the pipe break, the suppression chamber pressure rises to 27 psig within 25 seconds, equalizes with drywell pressure, and decays with the drywell pressure decay.

The design pressure of the drywell and suppression chamber is 56 psig. The design leak rate is 0.5-percent per day at the pressure of 56 psig. As pointed out above, the pressure response of the drywell and suppression chamber following an accident would be the same after about 25 seconds. Based on the calculated containment pressure response discussed above, the primary containment preoperational test pressures were chosen. Also based on the primary containment pressure response and the fact that the drywell and suppression chamber function as a unit, the primary containment will be tested as a unit rather than the individual components separately.

The calculated radiological doses given in Section 14.9 of the FSAR were based on an assumed leakage rate of 0.635-percent at the maximum calculated pressure of 49.6 psig. The doses calculated by the NRC using this bases are 0.14 rem, whole body passing cloud gamma dose, and 15.0 rem, thyroid dose, which are respectively only 5×10^{-3} and 10^{-1} times the 10 CFR 100 reference doses. Increasing the assumed leakage rate at 49.6 psig to 2.0 percent as indicated in the specifications would increase these doses approximately a factor of three, still leaving a margin between the calculated dose and the 10 CFR 100 reference values.

Establishing the test limit of 2.0-percent/day provides an adequate margin of safety to assure the health and safety of the general public. It is further considered that the allowable leak rate should not deviate significantly from the containment design value to take advantage of the design leak-tightness capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as built" condition is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable leak rate by 0.75 thereby providing a 25-percent margin to allow for leakage deterioration which may occur during the period between leak rate tests.

The primary containment leak rate test frequency is based on maintaining adequate assurance that the leak rate remains within the specification. The leak rate test frequency is based on the NRC guide for developing leak rate testing and surveillance of reactor containment vessels. Allowing the test intervals to be extended up to 10 months permits some flexibility needed to have the tests coincide with scheduled or unscheduled shutdown periods.

The penetration and air purge piping leakage test frequency, along with the containment leak rate tests, is adequate to allow detection of leakage trends. Whenever a bolted double-gasketed penetration is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. It is expected that the majority of the leakage from valves, penetrations and seals would be into the reactor building. However, it is possible that leakage into other parts of the facility could occur. Such leakage paths that may affect significantly the consequences of accidents are to be minimized.

The primary containment is normally slightly pressurized during periods of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase oxygen concentration. Once the containment is filled with nitrogen to the required concentration, determining the oxygen concentration twice a week serves as an added assurance that the oxygen concentration will not exceed 4 percent.

3.7.B/3.7.C Standby Gas Treatment System and Secondary Containment

The secondary containment is designed to minimize any ground level release of radioactive materials which might result from a serious accident. The reactor building provides secondary containment during reactor operation, when the drywell is sealed and in service; the reactor building provides primary containment, if required, when the reactor is shutdown and the drywell is open. Because the secondary containment is an integral part of the complete containment system, secondary containment is required at all times that primary containment is required as well as during refueling.

The standby gas treatment system is designed to filter and exhaust the reactor building atmosphere to the stack during secondary containment isolation conditions. All three standby gas treatment system fans are designed to automatically start upon containment isolation and to maintain the reactor building pressure to the design negative pressure so that all leakage should be in-leakage.

High efficiency particulate air (HEPA) filters are installed before and after the charcoal absorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine absorbers. The charcoal absorbers are installed to reduce the potential release of radioiodine to the environment. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal absorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 90 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal absorbers are as specified, the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal absorbers.

Only two of the three standby gas treatment systems are needed to clean up the reactor building atmosphere upon containment isolation. If one system is found to be inoperable, there is no immediate threat to the containment system performance and reactor operation or refueling operation may continue while repairs are being made. If more than one train is inoperable, all fuel handling operations, core alterations, and activities with the potential to drain any reactor vessel containing fuel must be suspended and all reactors placed in a cold shutdown condition, because the remaining train would provide only 50 percent of the capacity required to filter and exhaust the reactor building atmosphere to the stack. Suspension of these activities shall not preclude movement of a component to a safe, conservative position. Operations that have the potential for draining the reactor vessel must be suspended as soon as practical to minimize the probability of a vessel draindown and subsequent potential for fission product release. Draindown of a reactor vessel containing no fuel does not present the possibility for fuel damage or significant fission product release and therefore is not a nuclear safety concern.

4.7.B/4.7.C Standby Gas Treatment System and Secondary Containment

Initiating reactor building isolation and operation of the standby gas treatment system to maintain at least a 1/4 inch of water vacuum within the secondary containment provides an adequate test of the operation of the reactor building isolation valves, leak tightness of the reactor building and performance of the standby gas treatment system. Functionally testing the initiating sensors and associated trip logic demonstrates the capability for automatic actuation. Performing these tests prior to refueling will demonstrate secondary containment capability prior to the time the primary containment is opened for refueling. Periodic testing gives sufficient confidence of reactor building integrity and standby gas treatment system performance capability.

The test frequencies are adequate to detect equipment deterioration prior to significant defects, but the tests are not frequent enough to load the filters, thus reducing their reserve capacity too quickly. That the testing frequency is adequate to detect deterioration was demonstrated by the tests which showed no loss of filter efficiency after two years of operation in the rugged shipboard environment on the US Savannah (ORNL 3726). Pressure drop across the combined HEPA filters and charcoal adsorbers of less than six inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Heater capability, pressure drop and air distribution should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon refrigerant shall be performed in accordance with USAEC Report DP-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

All elements of the heater should be demonstrated to be functional and operable during the test of heater capacity. Operation of each filter train for a minimum of 10 hours each month will prevent moisture buildup in the filters and adsorber system.

With doors closed and fan in operation, DOP aerosol shall be sprayed externally along the full linear periphery of each respective door to check the gasket seal. Any detection of DOP in the fan exhaust shall be considered an unacceptable test result and the gaskets repaired and test repeated.

If significant painting, fire or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign material, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

Demonstration of the automatic initiation capability and operability of filter cooling is necessary to assure system performance capability. If one standby gas treatment system is inoperable, the other systems must be tested daily. This substantiates the availability of the operable systems and thus reactor operation and refueling operation can continue for a limited period of time.

3.7.D/4.7.D Primary Containment Isolation Valves

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the pressure suppression system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a LOCA.

Group 1 - Process lines are isolated by reactor vessel low water level ($\geq$ 398") in order to allow for removal of decay heat subsequent to a scram, yet isolate in time for proper operation of the core standby cooling systems. The valves in Group 1, except the reactor water sample line valves, are also closed when process instrumentation detects excessive main steam line flow, high radiation, low pressure, or main steam space high temperature. The reactor water sample line valves isolate only on reactor low water level at $\geq$ 398" or main steam line high radiation.

Group 2 - Isolation valves are closed by reactor vessel low water level (538") or high drywell pressure. The Group 2 isolation signal also "isolates" the reactor building and starts the standby gas treatment system. It is not desirable to actuate the Group 2 isolation signal by a transient or spurious signal.

Group 3 - Process lines are normally in use, and it is therefore not desirable to cause spurious isolation due to high drywell pressure resulting from nonsafety related causes. To protect the reactor from a possible pipe break in the system, isolation is provided by high temperature in the cleanup system area or high drain temperature. Also, since the vessel could potentially be drained through the cleanup system, a low-level isolation is provided.

Groups 4 and 5 - Process lines are designed to remain operable and mitigate the consequences of an accident which results in the isolation of other process lines. The signals which initiate isolation of Groups 4 and 5 process lines are therefore indicative of a condition which would render them inoperable.

Group 6 - Lines are connected to the primary containment but not directly to the reactor vessel. These valves are isolated on reactor low water level (538"), high drywell pressure, or reactor building ventilation high radiation which would indicate a possible accident and necessitate primary containment isolation.

Group 7 - (Deleted)

Group 8 - Line (traveling in-core probe) is isolated on high drywell pressure or reactor low water level (538"). This is to assure that this line does not provide a leakage path when containment pressure or reactor water level indicates a possible accident condition.

The maximum closure time for the automatic isolation valves of the primary containment and reactor vessel isolation control system have been selected in consideration of the design intent to prevent core uncovering following pipe breaks outside the primary containment and the need to contain released fission products following pipe breaks inside the primary containment.

In satisfying this design intent, an additional margin has been included in specifying maximum closure times. This margin permits identification of degraded valve performance prior to exceeding the design closure times.

In order to assure that the doses that may result from a steam line break do not exceed the 10 CFR 100 guidelines, it is necessary that no fuel rod perforation resulting from the accident occur prior to closure of the main steam line isolation valves. Analyses indicate that fuel rod cladding perforations would be avoided for main steam valve closure times, including instrument delay, as long as 10.5 seconds.

These valves are highly reliable, have low service requirements and most are normally closed. The initiating sensors and associated trip logic are also checked to demonstrate the capability for automatic isolation. The test interval of once per operating cycle for automatic initiation results in a failure probability of 1.1×10^{-7} that a line will not isolate. More frequent testing for valve operability in accordance with Specification 1.0.MM results in a greater assurance that the valve will be operable when needed.

The main steam line isolation valves are functionally tested per Specification 1.0.MM to establish a high degree of reliability.

The primary containment is penetrated by several small diameter instrument lines connected to the reactor coolant system. Each instrument line contains a 0.25-inch restricting orifice inside the primary containment and an excess flow check valve outside the primary containment.

3.7.E/4.7.E Control Room Emergency Ventilation

The control room emergency ventilation system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room emergency ventilation system is designed to automatically start upon control room isolation and to maintain the control room pressure to the design positive pressure so that all leakage should be out leakage. During cycle 6, CREVS has been declared inoperable only because it does not meet its design basis for essentially zero unfiltered inleakage. Reactor power operations and fuel movement are acceptable until just prior to startup for unit 2 cycle 7. During cycle 6, CREVS must be demonstrated to be functional by performing all applicable surveillances. In the event that the applicable surveillances are not successfully performed, the actions required by the LCOs must be complied with.

High efficiency particulate absolute (HEPA) filters are installed prior to the charcoal adsorbers to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential intake of radioiodine to the control room. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 90 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal adsorbers are as specified, the resulting doses will be less than the allowable levels stated in Criterion 19 of the General Design Criteria for Nuclear Power Plants, Appendix A to 10 CFR Part 50. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers.

If the system is found to be inoperable, there is no immediate threat to the control room and reactor operation or refueling operation may continue for a limited period of time while repairs are being made. If the system cannot be repaired within seven days, the reactor is shutdown and brought to Cold Shutdown within 24 hours or refueling operations are terminated.

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than six inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

Operation of the system for 10 hours every month will demonstrate operability of the filters and adsorber system and remove excessive moisture built up on the adsorber.

If significant painting, fire or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign materials, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

Demonstration of the automatic initiation capability is necessary to assure system performance capability.

3.7.F/4.7.F Primary Containment Purge System

The primary containment purge system is designed to provide air to purge and ventilate the primary containment system. The exhaust from the primary containment is first processed by a filter train assembly and then channeled through the reactor building roof exhaust system. During power operation, the primary containment purge and ventilation system is isolated from the primary containment by two isolation valves in series.

HEPA (high efficiency particulate air) filters are installed before the charcoal adsorbers followed by a centrifugal fan. The in-place test results should indicate a leak tightness of the system housing of not less than 99-percent and a HEPA efficiency of at least 99-percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 85-percent. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers.

If the system is found to be inoperable, the Standby Gas Treatment System may be used to purge the containment.

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than 8.5 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

If significant painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign materials, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

ENCLOSURE 2

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

AMENDMENT NO. 193 TO FACILITY OPERATING LICENSE NO. DPR-52

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT, UNIT 2

DOCKET NO. 50-260

1.0 INTRODUCTION

The Browns Ferry Nuclear (BFN) Plant Technical Specifications (TS) Table 3.7.A, "Primary Containment Isolation Valves," is being updated and corrected to reflect changes due to plant modifications and the BFN Appendix J Program. As such, the Tennessee Valley Authority (TVA, the licensee) submitted a license amendment application dated August 2, 1988 that would expand Table 3.7.A of the BFN TS for Units 1, 2, and 3 to include all primary containment isolation valves. By letter dated July 13, 1989, TVA supplemented its original amendment application with more detailed information regarding the primary containment isolation design scheme at BFN. However, it should be noted, that inorder to meet TVA's schedule for restart of Unit 2 the staff focused its efforts on this unit only. The aforementioned amendment application, and supplement, will have to be reviewed prior to restart of Units 1 and 3.

The proposed amendment would change the TS of BFN, Unit 2, to accomplish the following:

1. Combine the existing 10 CFR 50, Appendix J valve testing tables (Tables 3.7.D, E, and F) into the primary containment isolation valve table (Table 3.7.A) and delete the testable penetration tables (Tables 3.7.B, C, and H).

2. Add those valves to Table 3.7.A which have been incorporated into the Appendix J testing program and those which have been redefined as subject to the local leak rate test criteria of 0.60 La. Delete from Table 3.7.A two valves that are not containment isolation valves.

3. Correct Table 3.7.A to reflect plant configuration.

4. Add clarity to sections of Technical Specification 3.7/4.7.

Concomitant with the staff's safety evaluation (SE) of BFN's proposed changes to TS Table 3.7.A, "Primary Isolation Valves," the NRC staff reviewed the plant containment isolation arrangement for BFN. The SE below (Section 3.2), completes our review of BFN, Unit 2 containment isolation dependability as required by TMI Action Plan Issue II.E.4.2 (Parts 1-4) documented in NUREG-0737, "Clarification of TMI Action Plan Requirements." Furthermore, the staff evaluated BFN, Unit 2 compliance with 10 CFR Part 50, Appendix J.

2.0 Review Criteria

The Browns Ferry Nuclear Power Plant, Unit 2, began commercial operation in 1975 and was shut down in 1985 due to safety concerns. Since receiving their license, the safety review criteria have changed. As part of the Browns Ferry restart effort, the containment isolation system has been re-evaluated to current standards. The purpose of this evaluation is to document, for each containment penetration: the isolation arrangement, the applicable General Design Criteria, the deviations, if any, from the General Design Criteria and the basis for accepting the present isolation arrangement.

The safety criteria used in the staff's safety evaluation of the containment isolation system for BFN, Unit 2 are contained in the following references:

1. 10 CFR Part 50, Appendix A, General Design Criteria for Nuclear Power plants (GDC 54, 55, 56 and 57).

2. NUREG-0800, Standard Review Plan, Section 6.2.4, Containment Isolation System.

3. NUREG-0737, Clarification of TMI Action Plan Requirements, Section II.E.4.2, Parts 1-4.

4. 10 CFR Part 50, Appendix J, Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.

In addition to the review and evaluation of containment isolation arrangements for BFN, the staff reviewed the hazard potential inside containment resulting in high energy systems rupture causing jet impingement and/or missile damage to Reactor Building Closed Cooling Water (RBCCW) system inside containment. The evaluation below completes our review of BFN, Unit 2 high energy damage potential inside containment affecting RBCCW.

3.0 EVALUATION

3.1 Changes to TS Table 3.7.A, "Primary Containment Isolation Valves"

These changes pertain to Unit 2 primary containment isolation valves. Details of the proposed TS changes for specific systems are described below, as accompanied by the applicable staff evaluation.

A. RCIC and HPCI

Delete from Technical Specification Table 3.7.A the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) steamline drain valves (FCV-71-6A, 6B, and FCV-73-6A, 6B), the RCIC condensate pump drain valves (FCV-71-7A, 7B), and the HPCI hotwell pump discharge isolation valves (FCV-73-17A, 17B). Delete the Group 7 description from Bases Section 3.7. These valves described as "Group 7" isolation valves are system isolation valves. They perform no containment isolation function, nor do they receive a primary containment isolation signal (PCIS). The valves are located outboard of the primary containment isolation valves. The valves isolate only when the respective system turbine steam supply valve is not fully closed. Deleting these valves from Table 3.7.A will eliminate possible confusion as to the function and operability requirement of the valves. The staff finds these changes acceptable.

Delete HPCI/RCIC pump discharge isolation valves (FCV-73-44 and 71-39).

The HPCI/RCIC pump discharge isolation valves (FCV-71-39 and FCV-73-44) do not perform a containment isolation function. These valves automatically open on an accident signal to allow the systems to perform their safety function. The flowpaths for these systems contain two check valves in series which serve as automatic isolation valves under the BFN design basis described in FSAR Section 5.2.3.5. These check valves are now included in Table 3.7.A as containment isolation valves (they had previously been listed on Table 3.7.D). The staff finds these changes acceptable.

Add HPCI pump suction isolation valves (73-26, 73-27) to the Group 4 isolation valves.

The HPCI pump suction isolation valves have the same automatic isolation logic as the other Group 4 isolation valves. The staff finds this change acceptable.

B. <u>CAD SGTS</u>

Separate FCV-84-19 and FCV-84-20 (CAD System Torus/Drywell Exhaust to Standby Gas Treatment) into two entries in Table 3.7.A. FCV-84-20 is a Group 6 valve. FCV-84-19 will no longer be a Group 6 valve and will have no maximum operating time. A separate entry is proposed for FCV-84-20 with a Group 6 designator with no change to the existing technical specification requirements for this valve.

FCV 84-19 does not isolate on a Group 6 containment isolation signal. The valve is normally closed and requires a senior reactor operator to unlock the hand switch before the valve can be opened. This is acceptable to the staff.

C. <u>Appendix J Valve Testing Tables Combined</u>

Combine the existing 10 CFR 50, Appendix J testing tables (Tables 3.7.D, E, and F) into Table 3.7.A and make necessary changes to reflect the current BFN Appendix J Program. Pertinent notes are also added to designate the applicability of the valves in the revised Table 3.7.A to local leak rate testing. Changes to the BFN Appendix J testing programs have resulted in some valves being added to the program and other valves which have been redefined as being subject to the local leakage criteria of 0.6 of the allowable leak rate which is 655 SCF/HR and is abbreviated 0.60 La. The changes to the BFN Appendix J program are conservative changes that reflect current testing requirements.

Notes 1-5 and 7 are proposed to delineate specific local leak-rate testing applicability. Combining Tables 3.7.D, E, and F into Table 3.7.A and properly noting testing applicability should eliminate the confusion that exists when comparing Table 3.7.A to Tables 3.7.D, E, and F. The staff finds these changes relating to Appendix J testing tables and related TS notes acceptable.

D. Testable Penetration Tables

Delete testable penetration Tables 3.7.B, C and H.

BFN Technical Specification 4.7.A.2 requires that the provisions of the 10 CFR Part 50, Appendix J, be satisfied for BFN Units 1, 2, and 3. Furthermore, 10 CFR 50.54(o) requires that all water cooled power reactors meet the containment leakage test requirements set forth in Appendix J. Appendix J of 10 CFR Part 50 defines the primary containment penetrations for which Type B leak rate tests are required to be performed. Lists of primary penetrations for which Type B tests must be performed are maintained for BFN Units 1, 2, and 3 in the Appendix J Program (BFN Site Director Standard Practice 17.1). Since the information being deleted from BFN technical specification is contained in the Appendix J program, and since a test report listing the penetrations tested is required to be submitted for NRC review after each integrated leak rate test, no reductions in testing requirements or NRC review will result due to this change. The staff finds these changes acceptable.

E. Control Rod Hydraulic System

Delete control rod hydraulic return check valve (85-573).

This valve was physically removed from each unit per the recommendations of General Electric Service Information Letter 200-R2. The valve was inadvertently left in Table 3.7.A. This change will bring the technical specification Table 3.7.A up-to-date. The staff finds this change to be acceptable.

F. RHR

Delete the residual heat removal (RHR) flush and drain vent to suppression chamber valves FCV-74-102, 103, 119, and 120.

These valves are no longer isolation valves. The valves are still installed and are used for RHR drain and vent but are no longer connected to the primary containment. As they are no longer primary containment isolation valves, they have been deleted from the table. This change is acceptable to the staff.

G. Torus and Drywell Oxygen Sample Lines

Delete the torus and drywell oxygen sample line valves to analyzers A and B, FCV-76-51, 52, 53, 54, 61, 62, 63, and 64.

These valves have been deleted per an Engineering Change Notice (ECN). The staff finds these changes acceptable.

H. Containment Atmosphere Dilution Crosstie

Add the containment atmosphere dilution (CAD) crosstie to drywell control air check valve 84-617.

This valve has been added per a recent modification and provides long-term drywell control air capability. However, the staff expressed its concern to TVA regarding reliability of double check valve containment isolation for this newly designed system. Consequently, TVA has committed by letter dated February 27, 1991 to replace the outboard CAD check valve during the next refueling outage with a qualified, normally closed solenoid valve and a normally closed manual bypass valve (these valves will be included as part of the locked valve program). Furthermore, TVA committed to submit a followup TS amendment 120 days after restart of Unit 2 that designates these valves as primary containment isolation valves. The staff finds this acceptable.

I. Administrative Changes To TS To Revise Valve Descriptions

Make the following administrative changes to the technical specifications:

1. Add numbers to reactor water sample line isolation valves, FCV-43-13 and 14.

2. Change the reactor vessel water level isolation setpoint greater than or equal to 398 inches on the single asterisk note on Technical Specification Page 3.7/4.7-25 for Units 1 and 2 and Page 3.7/4.7-24 for Unit 3.

3. Revise descriptions of FCV-76-17, 18, and 19 and FCV-64-18 to more accurately identify their functions.

4. Add valve numbers to traversing incore probe (TIP) guide tubes, FCV-94-501, 502, 503, 504, and 505.

5. Change valve description (for FCV-73-81) to HPCI warmup. Change normal position to closed.

6. Move "Note 1" on Technical Specification Page 3.7/4.7-27 for Units 1 and 2 and Page 3.7/4.7-26 for Unit 3 to the notes for Table 3.7.A and renumber as note "Note 6." Change the normal position of the valves applicable to this note to "o/c" denoting open/closed, and the action on initiating signal to "GC/SC" denoting go closed/stay closed.

7. Editorial change to SR 4.7.A.2.g.

8. Correct errors in Table 3.7.A.

9. Renumber remaining pages of Section 3.7/4.7 to be consistent.

This item contains administrative changes to the technical specifications to revise valve descriptions, add unique valve identifiers to the tables, and other minor changes to the tables for consistency throughout. These changes are administrative in nature and as such, the staff finds this acceptable.

3.2 BFN Containment Isolation Dependability (TMI Action Item II.E.4.2.1-4) AND 10 CFR 50, Appendix J Testing

The NRC staff performed a thorough review of TVA BFN, Unit 2, containment isolation arrangement. The staff reviewed all containment systems and their isolation arrangement. The staff reviewed all containment systems and their associated penetrations except for the Post Accident Sampling System (PASS) and the Automatic Depressurization System (ADS) accumulators. The staff's review of the PASS and the ADS accumulators will be documented in a separate Safety Evaluation (SE) as part of TVA's TS Amendment Request No. 284.

The SE below was performed through a review of piping and flow diagrams, design documents provided by TVA, and a visit to the BFN facility documented by meeting summary dated August 17, 1990. TVA responded to the staff's recommendations regarding the primary containment isolation design arrangement at BFN, Unit 2, by letters dated September 17, 1990 and March 13, 1991.

Main Steam Line/Drain

Main Steam Line, Penetration 7A-D, and Main Steam Drain, Penetration 8, are classified as non-essential systems. Non-essential systems are the systems that are not required for post-accident mitigation. NUREG-0737, Clarification of TMI Action Requirements, Section II.E.4.2, Containment Isolation Dependability, Position (3) states that "All non-essential systems shall be automatically isolated by the containment isolation signal." The Main Steam Lines and Main Steam Drains have two air-operated globe valves on each, one inside and one outside of containment, that close at the occurrence of a Group 1 isolation signal. They utilize an air supply to open and a spring to close. Upon loss of the air supply the valve will fail close.

NUREG-0800, Standard Review Plan, Section 6.2.4, Containment Isolation System, Part II, Acceptance Criterion 1, states that "There should be diversity in the parameters sensed for the initiation of containment isolation..." The parameters that input into the Group 1 signal are: reactor vessel, low-low water level, main steam line high radiation, main steam line space high temperature, main steam line low pressure and main steam line high flow. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal.

The applicable General Design Criterion for these penetrations is 10 CFR Part 50 Appendix A, Criterion 55, Reactor Coolant Pressure Boundary Penetrating Containment. An acceptable isolation arrangement is stated in Criterion 55 Part 4, "One automatic isolation valve inside and one automatic isolation valve outside containment." The present isolation arrangement for the penetrations 7A-D and 8 meet the above stated acceptance criterion and is therefore acceptable.

10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-cooled Power Reactors," requires testing of containment isolation valves and penetrations for leakage if they communicate with the containment atmosphere. There are three types of tests that are required by Appendix J. However, for this evaluation the discussion will be limited to the local leak rate tests of the individual isolation barriers. These tests are known as Type C tests. Within this evaluation, Appendix J testing will be considered as Type C Appendix J testing.

The Main Steam Line and Main Steam Drain valves are tested in accordance with Appendix J guidelines and therefore are acceptable.

Demineralized Water

Demineralized Water, Penetration 20, is classified as a non-essential system. The Demineralized Water System has an inboard remote-manually operated globe valve and an outboard simple check valve. Both valves are tested in accordance with Appendix J.

This system penetrates the reactor coolant pressure boundary which makes GDC 55 the applicable design criterion. The GDC is not met in two areas. Because it is a non-essential system, the globe valve should be automatic rather than remote manual. In addition, the GDC does not allow a simple check valve to be used outside of containment.

The use of an outboard simple check valve is part of the original design basis but, does not meet the explicit requirements of the GDC. However, the staff has concluded that the location of the check valve is acceptable on "some other defined basis" due to the small reduction in the safety margin associated with the mislocation of the check.

To offset the use of a manual rather than an automatic valve, the staff recommended that the block valve (2-2-1191) used to test the check valve for leakage be considered as a locked closed isolation valve. The locked closed position is the most important element of the proposed resolution since it provides assurance that the block valve will be in the proper position. Appendix J testing is currently being performed and would not require any additional testing. In response to the staff's recommended resolution, by letter dated September 17, 1990, TVA chose not to designate the block valve as a containment isolation valve because they believe that the valve is currently tested in the reverse direction, and the line containing the valve is not seismically qualified. However, TVA did commit to include the manual globe containment isolation valve (2-2-1383) and block valve (2-2-1191) in the BFN locked valve program.

In spite of the limitations identified by TVA, the use of all three barriers is believed to be an acceptable isolation arrangement.

Reactor Feedwater

The Reactor Feedwater, penetration 9A & B, is classified as a non-essential system. The penetrations have two simple check valves on each line, one inside and one outside containment. Both of the check valves are Appendix J tested.

The double check valve arrangement is the original design basis for BFN. Although this design is part of BFN's original design, it is not in complete accordance with GDC 55. Reliance on only two simple check valves does not provide adequate long term isolation. After the initial event, the pressure differential across the check valve will decrease. The lower the differential pressure, the lower the confidence that the check will provide a leak-tight barrier. Therefore, the staff suggested that an additional valve be considered to provide complete protection in the long-term. This valve need not be automatic, since unnecessary isolation of this additional water source would not be in the direction of improved safety. For the short-term, the two check valves will provide the necessary leak-tight protection.

The Reactor Feedwater System has a downstream remote manual valve. To provide a more positive means of isolation the staff suggested that this valve be identified in the BFN Emergency Operating Instructions (EOI) as a valve that should be closed in some reasonable period of time. This added focus on the importance of the valve as a containment isolation valve should improve the overall reliability of the penetration and therefore provides additional assurance of long term isolation. TVA has committed to revise 2-EOI-3 to identify these valves.

The need to test this added valve was also evaluated. The current layout would require the addition of a valve to allow the testing of the remote manual valve and thereby fully meet all the requirements of an Appendix J test. However, this valve is used as a system isolation valve. As a result, the valve is regularly demonstrated to be leak tight under system pressure and temperature conditions. Although the tested medium is water rather than air, the staff has concluded that the operational verification of leak tightness is sufficient for purposes of a third valve. Therefore, this arrangement is acceptable based on TVA's commitment to identify the local manual valve in the EOI's. Further testing and qualification of these valves are not required.

By letter dated September 17, 1990, TVA committed to revise emergency operating instructions 2-EOI-3 to identify those valves (including the manual valve in this system) which potentially could be used for the isolation of leaks from high energy primary systems into secondary containment.

Auxiliary Boiler System

Auxiliary Boiler System, Penetration 210A, is classified as a non-essential system. Penetration 210A has two simple check valves located outside of containment as isolation barriers. This system is not acceptable to specific guidance provided in GDC 55, the applicable requirement. To upgrade this isolation arrangement, the staff recommended that the block valve used to test the check valve be incorporated as a containment isolation valve to provide a more positive means of isolation. TVA committed by letter dated September 17, 1990 to submit a TS amendment request that would formally cite this block valve (2-12-742), as a primary containment isolation valve within 120 days after restart. This block valve is currently tested with the associated check valves in accordance with the Appendix J testing program for containment isolation valves. BFN has placed several inboard isolation valves outside of containment. This is an acceptable practice due to the limited space within the containment. Limited space within the containment is typical of Mark I plants. The containment isolation system meets the requirement of GDC 55 Part 4 and is acceptable based on TVA's commitment to formally designate the block valve an isolation valve.

Control Air System

Control Air System, Penetration 48, is classified as a non-essential system. This system has two air operated plug valves in series located outside of containment that are Type A and Type C tested for leakage. They utilize an air supply to open and a spring to close. Upon loss of the air supply the valve will fail closed. These valves close upon a Group 6 isolation signal. Parameters input into the Group 6 signal are reactor vessel low water level, high drywell pressure and high radiation in reactor building ventilation exhaust. The parameters that input into the group signal meet the requirements of a diverse containment isolation signal.

This line connects to the containment atmosphere and therefore has to meet the criterion set forth in GDC 56, primary containment isolation. Part 4 of GDC 56 states that an acceptable isolation arrangement has "One automatic isolation valve inside and one automatic isolation valve outside containment." The placement of the inboard isolation valve outside of containment is acceptable on the basis stated above in the Auxiliary Boiler System. The containment isolation barriers meet the requirements of GDC Part 56 Part 4 and are therefore acceptable.

Service Air System

Service Air System, Penetration 21, is classified as a non-essential system. Penetration 21 has an inboard check valve and an outboard remote-manually operated globe valve that is Appendix J tested for leakage. GDC 56(2) states the applicable design criterion for this penetration, "One automatic isolation valve inside and one locked closed isolation valve outside of containment." To meet this criterion the globe valve would have to be added to the locked valve program. In response to the staff's recommendation, TVA committed by letter dated September 17, 1990 to add this globe valve (2-133-1070), to the locked valve program. The staff finds this arrangement to be acceptable.

Sampling and Water Quality System

Sampling and Water Quality System, Penetration 41, is classified as a non-essential system. Penetration 41 has an inboard and an outboard air operated globe valve as isolation barriers that are Appendix J tested for leakage. They utilize an air supply to open and a spring to close. Upon loss of the air supply, the valve will fail closed. These valves also isolate upon a Group 1 signal and the parameters that input into the Group 1 signal are listed in the Main Steam Line/Drain section. The parameters that input into the group signal meet the requirements of a diverse containment isolation signal. The isolation arrangement meets GDC 55 Part 4, stated in the Main Steam Line/Drain Section, and is therefore acceptable.

Standby Liquid Control

Standby Liquid Control, Penetration 42, is classified as an essential system. Essential systems are systems whose function is needed for post-accident mitigation. Penetration 42 has a double check valve arrangement, one inside and one outside containment. Essential systems need to have the capability of isolation after it is determined that the system is no longer needed for accident mitigation. Downstream from the outboard check valve, there is an explosive valve that will serve as another isolation barrier capable of final system isolation. Although, this additional barrier is lost when the system is called upon to operate (e.g., anticipated transients without scram), it does provide positive isolation under all other conditions. In spite of this limitation, the staff finds the containment isolation arrangement acceptable.

Containment Ventilation System

Containment Ventilation System, Penetration 25, is classified as a non-essential system. Penetration 25 has three air operated butterfly valves as isolation barriers that are Appendix J tested for leakage. These valves isolate upon a Group 6 signal and the parameters that input into the Group 6 signal are listed above in the Control Air Section. The parameters that input into the group signal meet the requirements of a diverse containment isolation signal. This isolation arrangement meets the requirements of GDC 55 Part 4 and is therefore acceptable.

Recirculation System

Recirculation System, Penetrations 37C and 38C, are classified as a non-essential system. Penetrations 37C and 38C have double check valve arrangements as isolation barriers, one inside and one outside containment which are Appendix J tested for leakage. GDC 55 Part 2 requires a locked closed boundary outside containment for acceptance. The downstream remote-manual valve has been identified in the EOI's as a final isolation boundary and this isolation arrangement is acceptable on the basis stated above in the Reactor Feedwater Section.

Reactor Water Cleanup System

Reactor Water Cleanup (RWCU) injection, Penetration 9B, is classified as a non-essential system. Penetration 9B has a double check valve arrangement as an isolation barrier, one inside and one outside containment that are Appendix J tested for leakage. To diversify this isolation arrangement, a downstream isolation valve has been identified in the EOI's as a final isolation boundary to meet the requirements of GDC 55 Part 2. By letter dated September 17, 1990, TVA committed to include this kind of remote manual valve in the EOI's as an isolation valve that will be used for positive isolation of the system.

RWCU supply, Penetration 14, is classified as a non-essential system. It has an inboard and an outboard motor operated gate valve as containment isolation barriers. These valves isolate upon a Group 1 signal. The parameters that input into the signal are listed above in the Main Steam Line/Drain section. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This arrangement meets the criterion set forth in GDC 55 Part 4 and is acceptable.

Reactor Building Closed Cooling Water

The Reactor Building Closed Cooling Water (RBCCW) system, Penetrations 23 and 24, is classified as a non-essential system. Penetration 23, RBCCW return, has an outboard remote-manually operated gate valve and Penetration 24, RBCCW Supply, has an outboard check valve. Both valves are Appendix J tested. TVA regards this system as a closed system inside containment. However, the staff recommended that TVA take the following action to assure the integrity of RBCCW as a closed system: 1) assess the pipe restraint program for all drywell piping, 2) identify those components or sources in the drywell which could become missiles and possibly endanger the RBCCW integrity inside of containment, and 3) establish procedures for manual isolation of all coolers upon receipt of an isolation signal to minimize loss of RBCCW integrity.

By letter dated September 17, 1990, TVA responded to the staff recommendations mentioned above. TVA indicated in their response that seismic Class I piping restraints inside the drywell were assessed as part of the program to comply with Bulletin 79-14, and that current plant design does not permit manual isolation of the coolers. With regard to potential missiles inside containment and their threat to the RBCCW system, TVA provided the results of system walkdowns and vulnerability studies by letter dated March 11, 1991. The staff finds TVA's conclusions and existing containment isolation arrangement acceptable.

Reactor Core Isolation Cooling System

Reactor Core Isolation Cooling (RCIC) injection, Penetration 9B, is classified as an essential system. Penetration 9B has a testable check as an isolation barrier which is Appendix J tested. Testable check valves are designed for remote opening with zero differential pressure across the valve seat. The valve will close on reverse flow even though the test switches may be positioned for open. The valve opens when pump pressure exceeds reactor pressure even though the test switch may be positioned for close.

The RCIC system also has a downstream (remote manual) valve that would provide a more positive means of isolation. Reliance on only the check valve does not provide adequate long-term isolation. After the initial event, the pressure differential across the check valve will decrease. The lower the differential pressure, the lower the confidence that the check will provide a leak tight barrier. Therefore, the additional valve downstream should be added to provide long-term protection. This valve is presently Appendix J tested so further qualification of the valve would not be needed. By letter dated September 17, 1990, TVA committed to include this valve in the EOIs to provide operators with another valve that can be used to assure positive system isolation.

RCIC steam supply, Penetration 10, is classified as an essential system. Penetration 10 has an inboard and an outboard motor operated gate valve as containment isolation barriers. These valves isolate upon a Group 5 signal. This isolation signal is not a containment isolation signal but a system isolation signal. Line break in the RCIC system steam line to turbine (high steam line space temperature, high steam flow, or low steam line pressure) and high pressure between rupture discs on RCIC turbine exhaust are the input parameters into the isolation signal. The parameters that input into this isolation signal detect a rupture in the RCIC system and low steam pressure to protect the turbine. This isolation arrangement is acceptable based on its ability to (1) be isolated by an operator after the system has performed its accident mitigation function and (2) to automatically isolate in the event of low steam pressure or system piping failure.

High Pressure Core Injection System

High Pressure Core Injection (HPCI) system injection, Penetration 9A, is classified as an essential system. Penetration 9A has a testable check as an isolation barrier which is Appendix J tested. The HPCI system also has a downstream (remote manual) valve that would provide a more positive means of isolation. Reliance on only the check valve does not provide adequate long-term isolation. After the initial event, the pressure differential across the check valve will decrease. The lower the differential pressure, the lower the confidence that the check will provide a leak tight barrier. Therefore, the additional valve downstream should be added to provide complete protection in the long term. This valve is presently Appendix J tested so no further qualification of the valve would be needed. By letter dated September 17, 1990, TVA committed to include this manual valve in the EOIs to provide the operators with another valve that can be used to assure positive system isolation.

HPCI steam supply, Penetration 11, is classified as an essential system. Penetration 11 has an inboard and an outboard motor-operated gate valve as a containment isolation barrier. These valves isolate upon a Group 4 signal. This isolation signal is not a containment isolation signal but a system isolation signal. Line break in HPCI system line to turbine (high steam line space temperature, high steam flow, or low steam line pressure) and HPCI pressure between diaphragm rupture discs on turbine exhaust are the input parameter into the group signal. The parameters that input the isolation signal detect a rupture in the HPCI system and low steam pressure to protect the turbine. This isolation arrangement is acceptable based on its ability to (1) be isolated by an operator after the system has performed its accident mitigation function and (2) to automatically isolate in the event of low steam pressure or system piping failure.

Residual Heat Removal System

Residual Heat Removal (RHR) shutdown cooling discharge, Penetrations 13A and B, are classified as essential systems. Penetration 13A and B have an inboard testable check valve, and an outboard motor-operated gate valve as isolation barriers.

The gate valve isolates upon a Group 2 signal. Reactor vessel low water level and high drywell pressure are the input parameters for the Group 2 signal. The parameters that input into the group isolation signal meet the requirements of the diverse isolation signal. This isolation arrangement meets GDC 55 and is therefore acceptable.

RHR shutdown cooling supply, Penetration 12, is classified as a non-essential system. The penetration has an inboard and an outboard motor-operated gate valve as isolation barriers. These valves isolate upon a Group 2 signal. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This arrangement meets the criterion set forth in GDC 55 Part 4 and is acceptable.

RHR recirculation and pump test lines presently rely upon the suppression pool as one of the isolation barriers. The staff does not consider the suppression pool an adequate barrier, and suggested to TVA that an existing test valve could be designated the containment isolation boundary. TVA has subsequently committed (via teleconference), to identify these test valves (one in each train) as containment isolation valves in the BFN TS. TVA will submit a TS amendment to this effect within 120 days after restart.

Core Spray System

Core Spray Injection, Penetrations 16A & B, are classified as an essential system. Penetration 16A and B have outboard remote manually operated gate valves and inboard testable check valves as isolation barriers. These valves are leakage tested in accordance with Appendix J. This arrangement deviates from the GDC because of its classification as an essential system. The GDC acceptance criterion requires the system to be automatically isolated upon a containment isolation signal or it can be acceptable on another defined basis. The other defined basis is the system's function as an essential system needed for accident mitigation. This system has the ability to be remote-manually isolated after the system has confirmed its accident mitigation function; therefore, this deviation is acceptable.

Drywell Drains

Drywell Drain, Penetrations 18 & 19, is classified as a non-essential system. Penetrations 18 and 19 have two outboard air operated gate valves as an isolation barrier. These valves close on a Group 2 isolation signal and are leak tested in accordance with Appendix J. The inputs into the signal are listed above in the RHR Shutdown Discharge section. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This arrangement is acceptable based on the above discussion in the Control Air System section.

Containment Inerting

H_2 sample line, Penetrations 52C, 229D & K, are classified as a non-essential system. Penetration 52C, 229D and K have two outboard solenoid operated gate valves as isolation barriers. These valves close upon a Group 6 signal and are leak tested in accordance with Appendix J. The parameters that input into the group isolation signal meet the requirements of diverse isolation signal. This system meets the requirements of GDC 56(4) and is acceptable.

H_2 Purge Sample line, Penetration 27F, is classified as a non-essential system. Penetration 27F has two outboard solenoid operated gate valves as isolation barriers. These valves isolate upon a Group 6 signal and are leak tested in accordance with Appendix J. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This system meets the requirements of GDC 56(4) and is acceptable.

H_2O_2 sample return line, Penetrations 229B & G, are classified as a non-essential system. Penetration 229B and G have two outboard solenoid operated gate valves as isolation barrier. These valves isolate upon a Group 6 signal and are leak tested in accordance with Appendix J. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This system meets the requirements of GDC 56(4) and is acceptable.

Containment Atmosphere Dilution

Containment Atmosphere Dilution (CAD) System, Penetration 25, is classified as an essential system. Penetration 25 has two outboard remote-manually operated solenoid valves and two outboard check valves. These valves are leak tested in accordance with Appendix J. The use of an outboard simple check valve is part of the original design basis but, does not meet the explicit requirements of GDC 56. However, the staff has concluded that the location of the check valve is acceptable on "some other defined basis" due to the small reduction in the safety margin associated with the mislocation of the check. This system is acceptable on that basis.

Radiation Monitoring System

Drywell CAM Suction, Penetrations 50A & D, are classified as a non-essential system. Penetrations 50A and D have two outboard motor operated ball valves as isolation barriers. These valves close upon a Group 6 signal and are leak tested in accordance with Appendix J. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This system meets the requirements of GDC 56(4) and is acceptable.

Drywell CAM discharge, Penetration 50C, is classified as a non-essential system. Penetration 50C has two outboard motor operated ball valves as isolation barriers. These valves close upon a Group 6 isolation signal and are leak tested in accordance with Appendix J. The parameters that input into the group isolation signal meet the requirements of a diverse isolation signal. This system meets the requirements of GDC 56(4) and is acceptable.

4.0 ENVIRONMENTAL CONSIDERATION

The amendment involves a change to a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes to the surveillance requirements. The staff has determined that this amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that this amendment involves no significant hazards consideration and there has been no public comment on such finding. Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement nor environmental assessment need be prepared in connection with the issuance of this amendment.

5.0 CONCLUSION

The Commission made a proposed determination that the amendment involves no significant hazards consideration which was published in the Federal Register (53 FR 37378) on September 26, 1988, and consulted with the State of Alabama. No public comments were received and the State of Alabama did not have any comments.

The staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security nor to the health and safety of the public.

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