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

July 22, 1982

Posted
Amdt. 82
to DPR-52

Docket Nos. 50-259
50-260
and 50-296

Mr. Hugh G. Parris
Manager of Power
Tennessee Valley Authority
500 A Chestnut Street, Tower II
Chattanoga, Tennessee 37401

Dear Mr. Parris:

The Commission has issued the enclosed Amendment Nos. 85, 82 and 56 to Facility License Nos. DPR-33, DPR-52 and DPR-68 for the Browns Ferry Nuclear Plant, Unit Nos. 1, 2 and 3. These amendments are in response to your application dated May 15, 1981 (TVA BFNP TS 162), as supplemented by your letters of June 16, 1981 and September 28, 1981.

These revisions to the Technical Specifications consist of clarification and adminstrative changes, additions to reflect plant modifications and reorganization of some sections.

Copies of the Safety Evaluation and Notice of Issuance are also enclosed.

Sincerely,

Richard J. Clark

Richard J. Clark, Project Manager
Operating Reactors Branch #2
Division of Licensing

Enclosures:
1. Amendment No. 85 to DPR-33
2. Amendment No. 82 to DPR-52
3. Amendment No. 56 to DPR-68
4. Safety Evaluation
5. Notice

cc: w/enclosures:
See next page

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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 NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 82
License No. DPR-52

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

   A. The application for amendments by Tennessee Valley Authority (the licensee), dated May 15, 1981, as supplemented by letters dated June 16, 1981 and September 28, 1981, 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 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. 82, 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 the date of its issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Domenic B. Vassallo, Chief
Operating Reactors Branch #2
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: July 22, 1982

ATTACHMENT TO LICENSE AMENDMENT NO. 82

FACILITY OPERATING LICENSE NO. DPR-52

DOCKET NO. 50-260

A. Revise Appendix A as follows:

1. Replace the following pages with identically numbered pages:

8	40	74	
9	41	78	252
10	44	87	259
11	53	121	260
23	55	173	262
24	56	175	293a
33	57	180	302
34	58	182	303
36	59	235	319
38	61	251	356
	60		

Marginal lines on the above pages indicate the areas being revised.

2. The overleaf pages are not being revised and should be retained.

3. Add the following new pages:

251A
261A

B. Revise Appendix B as follows:

1. Replace the following pages with identically numbered pages:

11
25

2. The overleaf pages are not being revised and should be retained.

1.1 FUEL CLADDING INTEGRITY

Applicability

Applies to the interrelated variables associated with fuel thermal behavior.

Objective

To establish limits which ensure the integrity of the fuel cladding.

Specifications

A. Thermal Power Limits

1. Reactor Pressure > 800 psia and Core Flow > 10% of Rated.

   When the reactor pressure is greater than 800 psia, the existence of a minimum critical power ratio (MCPR) less than 1.07 shall constitute violation of the fuel cladding integrity safety limit.

2.1 FUEL CLADDING INTEGRITY

Applicability

Applies to trip settings of the instruments and devices which are provided to prevent the reactor system safety limits from being exceeded.

Objective

To define the level of the process variables at which automatic protective action is initiated to prevent the fuel cladding integrity safety limit from being exceeded.

Specification

The limiting safety system settings shall be as specified below:

A. Neutron Flux Trip Settings

1. APRM Flux Scram Trip Setting (Run Mode)

   a. When the Mode Switch is in the RUN position, the APRM flux scram trip setting shall be:

$$S \leq (0.66W + 54\%)$$

where:

S = Setting in percent of rated thermal power (3293 MWt)

W = Loop recirculation flow rate in percent of rated (rated loop recirculation flow rate equals 34.2×10^6 lb/hr)

1.1 FUEL CLADDING INTEGRITY

2.1 FUEL CLADDING INTEGRITY

b. In the event of operation with the core maximum fraction of limiting power density (CMFLPD) greater than fraction of rated thermal power (FRP) the setting shall be modified as follows:

$$S \leq (0.66W + 54\%) \frac{FRP}{CMFLPD}$$

c. For no combination of loop recirculation flow rate and core thermal power shall the APRM flux scram trip setting be allowed to exceed 120% of rated thermal power.

(Note: These settings assume operation within the basic thermal hydraulic design criteria. These criteria are LHGR ≤ 18.5 kw/ft for 7x7 fuel and ≤ 13.4 kw/ft for 8x8, 8x8R, and P8x8R, and MCPR within limits of Specification 3.5.k. If it is determined that either of these design criteria is being violated during operation, action shall be initiated within 15 minutes to restore operation within prescribed limits Surveillance requirements for APRM scram setpoint are given in specification 4.1.B.

d. The APRM Rod block trip setting shall be:

$$S_{RB} \leq (0.66W + 42\%)$$

where:

S_{RB} = Rod block setting in percent of rated thermal power (3293 MWt)

W = Loop recirculation flow rate in percen of rated (rated loop recirculation flow rate equals 34.2×10^6 lb/hr)

SAFETY LIMIT	LIMITING SAFETY SYSTEM SETTING
1.1 FUEL CLADDING INTEGRITY	2.1 FUEL CLADDING INTEGRITY
	In the event of operation with the core maximum fraction of limiting power density (CMFLPD) greater than fraction of rated thermal power (FRP) the setting shall be modified as follows: $S_{RB} \leq \{0.66W + 42\%\} \frac{FRP}{CMFLPD}$
2. Reactor Pressure ≤800 PSIA or Core Flow ≤10% of rated. When the reactor pressure is ≤800 PSIA or core flow is ≤10% of rated, the core thermal power shall not exceed 823 MWt (~25% of rated thermal power).	2. APRM and IRM Trip Settings (Startup and Hot Standby Modes). a. APRM--When the reactor mode switch is in the STARTUP position, the APRM scram shall be set at less than or equal to 15% of rated power. b. IRM--The IRM scram shall be set at less than or equal to 120/125 of full scale.

SAFETY LIMIT	LIMITING SAFETY SYSTEM SETTING

1.1 FUEL CLADDING INTEGRITY

B. Power Transient

To ensure that the Safety Limits established in Specification 1.1.A are not exceeded, each required scram shall be initiated by its expected scram signal. The Safety Limit shall be assumed to be exceeded when scram is accomplished by means other than the expected scram signal.

C. Reactor Vessel Water Level

Whenever there is irradiated fuel in the reactor vessel, the water level shall not be less than 17.7 in. above the top of the normal active fuel zone.

2.1 FUEL CLADDING INTEGRITY

B. Power Transient Trip Settings

1. Scram and isolation (PCIS groups 2,3,6) reactor low water level	≥ 538 in. above vessel zero
2. Scram--turbine stop valve closure	≤ 10 percent valve closure
3. Scram--turbine control valve fast closure or turbine trip	≥ 550 psig
4. Scram--low condenser vacuum	≥ 23 inches Hg vacuum
5. Scram--main steam line isolation	≤ 10 percent valve closure
6. Main steam isolation valve closure --nuclear system low pressure	≥ 825 psig

C. Water Level Trip Settings

1. Core spray and LPCI actuation--reactor low water level	≥ 378 in. above vessel zero
2. HPCI and RCIC actuation--reactor low water level	≥ 470 in. above vessel zero
3. Main steam isolation valve closure--reactor low water level	≥ 470 in. above vessel zero

from fuel damage, assuming a steady-state operation at the trip setting, over the entire recirculation flow range. The margin to the Safety Limit increases as the flow decreases for the specified trip setting versus flow relationship; therefore, the worst case MCPR which could occur during steady-state operation is at 108% of rated thermal power because of the APRM rod block trip setting. The actual power distribution in the core is established by specified control rod sequences and is monitored continuously by the in-core LPRM system. As with the APRM scram trip setting, the APRM rod block trip setting is adjusted downward if the CMFLPD exceeds FRP thus preserving the APRM rod block safety margin.

C. Reactor Water Low Level Scram and Isolation (Except Main Steamlines)

The set point for the low level scram is above the bottom of the separator skirt. This level has been used in transient analyses dealing with coolant inventory decrease. The results reported in FSAR subsection 14.5 show that scram and isolation of all process lines (except main steam) at this level adequately protects the fuel and the pressure barrier, because MCPR is greater than 1.07 in all cases, and system pressure does not reach the safety valve settings. The scram setting is approximately 31 inches below the normal operating range and is thus adequate to avoid spurious scrams.

D. Turbine Stop Valve Closure Scram

The turbine stop valve closure trip anticipates the pressure, neutron flux and heat flux increases that would result from closure of the stop valves. With a trip setting of 10% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained even during the worst case transient that assumes the turbine bypass valves remain closed. (Reference 2)

E. Turbine Control Valve Fast Closure or Turbine Trip Scram

Turbine control valve fast closure or turbine trip scram anticipates the pressure, neutron flux, and heat flux increase that could result from control valve fast closure due to load rejection or control valve closure due to turbine trip; each without bypass valve capability. The reactor protection system initiates a scram in less than 30 milliseconds after the start of control valve fast closure due to load rejection or control valve closure due to turbine trip. This scram is achieved by rapidly reducing hydraulic control oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the reactor protection system. This trip setting, a nominally 50% greater closure time and a different valve characteristic from that of the turbine stop valve, combine to produce transients very similar to that for the stop valve. No significant change in MCPR occurs. Relevant transient analyses are discussed in References 2 and 3 of the Final Safety Analysis Report. This scram is bypassed when turbine steam flow is below 30% of rated, as measured by turbine first state pressure.

F. Main Condenser Low Vacuum Scram

To protect the main condenser against overpressure, a loss of condenser vacuum initiates automatic closure of the turbine stop valves. To anticipate the transient and automatic scram resulting from the closure of the turbine stop valves, low condenser vacuum initiates a scram. The low vacuum scram set point is selected to initiate a scram before the closure of the turbine stop valves is initiated.

G. & H. Main Steam Line Isolation on Low Pressure and Main Steam Line Isolation Scram

The low pressure isolation of the main steam lines at 825 psig was provided to protect against rapid reactor depressurization and the resulting rapid cooldown of the vessel. Advantage is taken of the scram feature that occurs when the main steam line isolation valves are closed, to provide for reactor shutdown so that high power operation at low reactor pressure does not occur, thus providing protection for the fuel cladding integrity safety limit. Operation of the reactor at pressures lower than 825 psig requires that the reactor mode switch be in the STARTUP position, where protection of the fuel cladding integrity safety limit is provided by the IRM and APRM high neutron flux scrams. Thus, the combination of main steam line low pressure isolation and isolation valve closure scram assures the availability of neutron flux scram protection over the entire range of applicability of the fuel cladding integrity safety limit. In addition, the isolation valve closure scram anticipates the pressure and flux transients that occur during normal or inadvertent isolation valve closure. With the scram set at 10 percent of valve closure, neutron flux does not increase.

TABLE 3.1.A

REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENT

Min. No. of Operable Inst. Channels Per Trip System (1)	(23) Trip Function	Trip Level Setting	Modes in Which Function Must Be Operable: Shut-down	Refuel (7)	Startup/Hot Standby	Run	Action (1)
1	Mode Switch in Shutdown		X	X	X	X	1.A
1	Manual Scram		X	X	X	X	1.A
3	IRM (16) High Flux	≤ 120/125 Indicated on scale	X(22)	X (22)	X	(5)	1.A
3	Inoperative			X	X	(5)	1.A
2	APRM (16) High Flux	See Spec. 2.1.A.1		X (21)	X(17)	X	1.A or 1.B
2	High Flux	≤ 15% rated power (13)		X (21)	X(17)	(15)	1.A or 1.B
2	Inoperative			(11)	(11)	X	1.A or 1.B
2	Downscale	≥ 3 Indicated on Scale				X(12)	1.A or 1.B
2	High Reactor Pressure	≤ 1055 psig		X(10)	X	X	1.A
2	High Drywell Pressure (14)	≤ 2.5 psig		X(8)	X(8)	X	1.A
2	Reactor Low Water Level (14)	≥ 538" above vessel zero		X	X	X	1.A
2	High Water Level in Scram Discharge Tank	≤ 50 Gallons	X	X(2)	X	X	1.A

TABLE 3.1.A
REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENT

Min. No. of Operable Inst. Channels Per Trip System (1)(23)	Trip Function	Trip Level Setting	Modes in Which Function Must Be Operable: Shut-down	Refuel (7)	Startup/Hot Standby	Run	Action(1)
4	Main Steam Line Isolation Valve Closure	≤ 10% Valve Closure		X(3)(6)	X(3)(6)	X(6)	1.A or 1.C
2	Turbine Cont. Valve Fast Closure or Turbine Trip	≥ 550 psig				X(4)	1.A or 1.D
4	Turbine Stop Valve Closure	≤ 10% Valve Closure				X(4)	1.A or 1.D
2	Turbine First Stage Pressure Permissive	not ≥ 154 psig		X(18)	X(18)	X(18)	(19)
2	Turbine Condenser Low Vacuum	≥ 23 In. Hg, Vacuum		X(3)	X(3)	X	1.A or 1.C
2	Main Steam Line High Radiation (14)	3X Normal Full Power Background (20)		X(9)	X(9)	X(9)	1.A or 1.C

10. Not required to be operable when the reactor pressure vessel head is not bolted to the vessel.

11. The APRM downscale trip function is only active when the reactor mode switch is in run.

12. The APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not high.

13. Less than 14 operable LPRM's will cause a trip system trip.

14. Channel shared by Reactor Protection System and Primary Containment and Reactor Vessel Isolation Control System. A channel failure may be a channel failure in each system.

15. The APRM 15% scram is bypassed in the Run Mode.

16. Channel shared by Reactor Protection System and Reactor Manual Control System (Rod Block Portion). A channel failure may be a channel failure in each system. If a channel is allowed to be INOPERABLE per Table 3.1.A, the corresponding function in that same channel may be inoperable in the Reactor Manual Control System (Rod Block).

17. Not required while performing low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5 MW(t).

18. This function must inhibit the automatic bypassing of turbine control valve fast closure or turbine trip scram and turbine stop valve closure scram whenever turbine first stage pressure is greater than or equal to 154 psig.

19. Action 1.A or 1.D shall be taken only if the permissive fails in such a manner to prevent the affected RPS logic from performing its intended function. Otherwise, no action is required.

20. The nominal setpoints for alarm and reactor trip (1.5 and 3.0 times background, respectively) are established based on the normal background at full power. The allowable setpoints for alarm and reactor trip are 1.2-1.8 and 2.4-3.6 times background, respectively.

21. The APRM High Flux and Inoperative Trips do not have to be operable in the Refuel Mode if the Source Range Monitors are connected to give a non-coincidence, High Flux scram, at 5×10^5 cps. The SRM's shall be operable per Specification 3.10.B.1. The removal of eight (8) shorting links is required to provide non-coincidence high-flux scram protection from the Source Range Monitors.

22. The three required IRM's per trip channel is not required in the Shutdown or Refuel Modes if at least four IRM's (one in each core quadrant) are connected to give a non-coincidence, High Flux scram. The removal of four (4) shorting links is required to provide non-coincidence high-flux scram protection from the IRM's.

23. A channel may be placed in an inoperable status for up to 4 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

TABLE 4.1.A
REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION FUNCTIONAL TESTS
MINIMUM FUNCTIONAL TEST FREQUENCIES FOR SAFETY INSTR. AND CONTROL CIRCUITS

	Group (2)	Functional Test	Minimum Frequency (3)
Main Steam Line Isolation Valve Closure	A	Trip Channel and Alarm	Once/Month (1)
Turbine Control Valve Fast Closure or Turbine Trip	A	Trip Channel and Alarm	Once/Month (1)
Turbine First Stage Pressure Permissive	A	Trip Channel and Alarm	Every 3 Months
Turbine Stop Valve Closure	A	Trip Channel and Alarm	Once/Month (1)

TABLE 4.1.B
REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENT CALIBRATION
MINIMUM CALIBRATION FREQUENCIES FOR REACTOR PROTECTION INSTRUMENT CHANNELS

Instrument Channel	Group (1)	Calibration	Minimum Frequency (2)
IRM High Flux	C	Comparison to APRM on Controlled startups (6)	Note (4)
APRM High Flux			
Output Signal	B	Heat Balance	Once every 7 days
Flow Bias Signal	B	Calibrate Flow Bias Signal (7)	Once/operating cycle
LPRM Signal	B	TIP System Traverse (8)	Every 1000 Effective Full Power Hours
High Reactor Pressure	A	Standard Pressure Source	Every 3 Months
High Drywell Pressure	A	Standard Pressure Source	Every 3 Months
Reactor Low Water Level	A	Pressure Standard	Every 3 Months
High Water Level in Scram Discharge Volume	A	Note (5)	Note (5)
Turbine Condenser Low Vacuum	A	Standard Vacuum Source	Every 3 Months
Main Steam Line Isolation Valve Closure	A	Note (5)	Note (5)
Main Steam Line High Radiation	B	Standard Current Source (3)	Every 3 Months
Turbine First Stage Pressure Permissive	A	Standard Pressure Source	Every 6 Months
Turbine Stop Valve Closure	A	Note (5)	Note (5)

NOTES FOR TABLE 4.1.B

1. A description of three groups is included in the bases of this specification.

2. Calibrations are not required when the systems are not required to be operable or are tripped. If calibrations are missed, they shall be performed prior to returning the system to an operable status.

3. The current source provides an instrument channel alignment. Calibration using a radiation source shall be made each refueling outage.

4. Required frequency is initial startup following each refueling outage.

5. Physical inspection and actuation of these position switches will be performed once per operating cycle.

6. On controlled startups, overlap between the IRM's and APRM's will be verified.

7. The Flow Bias Signal Calibration will consist of calibrating the sensors, flow converters, and signal offset networks during each operating cycle. The instrumentation is an analog type with redundant flow signals that can be compared. The flow comparator trip and upscale will be functionally tested according to Table 4.2.C to ensure the proper operating during the operating cycle. Refer to 4.1 Bases for further explanation of calibration frequency.

8. A complete tip system traverse calibrates the LPRM signals to the process computer. The individual LPRM meter readings will be adjusted as a minimum at the beginning of each operating cycle before reaching 100% power.

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modes. In the power range the APRM system provides required protection. Ref. Section 7.5.7 FSAR. Thus, the IRM System is not required in the Run mode. The APRM's and the IRM's provide adequate coverage in the startup and intermediate range.

The high reactor pressure, high drywell pressure, reactor low water level and scram discharge volume high level scrams are required for Startup and Run modes of plant operation. They are, therefore, required to be operational for these modes of reactor operation.

The requirement to have the scram functions as indicated in Table 3.1.1 operable in the Refuel mode is to assure that shifting to the Refuel mode during reactor power operation does not diminish the need for the reactor protection system.

The turbine condenser low vacuum scram is only required during power operation and must be bypassed to start up the unit. Below 154 psig turbine first stage pressure (30% of rated), the scram signal due to turbine stop valve closure, and turbine control valve fast closure, is bypassed because flux and pressure scram are adequate to protect the reactor.

Because of the APRM downscale limit of $\geq$ 3% when in the Run mode and high level limit of $\leq$ 15% when in the Startup Mode, the transition between the Startup and Run Modes must be made with the APRM instrumentation indicating between 3% and 15% of rated power or a control rod scram will occur. In addition, the IRM system must be indicating below the High Flux setting (120/125 of scale) or a scram will occur when in the Startup Mode. For normal operating conditions, these limits provide assurance of overlap between the IRM system and APRM system so that there are no "gaps" in the power level indications (i.e., the power level is continuously monitored from beginning of startup to full power and from full power to shutdown). When power is being reduced, if a transfer to the Startup mode is made and the IRM's have not been fully inserted (a maloperational but not impossible condition) a control rod block immediately occurs so that reactivity insertion by control rod withdrawal cannot occur.

3.2.H Flood Protection

The unit shall be shutdown and placed in the cold condition when Wheeler Reservoir lake stage rises to a level such that water from the reservoir begins to run across the pumping station deck at elevation 565.

Requirements for instrumentation that monitors the reservoir level is given in Table 3.2.H.

4.2.H Flood Protection

Surveillance shall be performed on the instrumentation that monitors the reservoir level as indicated in Table 4.2.H.

3.2.I Meteorological Monitoring Instrumentation

The meteorological monitoring instrumentation listed in table 3.2.I shall be operable at all times.

1. With the number of operable meteorological monitoring channels less than required by table 3.2.I, restore the inoperable channel(s) to operable status within 7 days.

2. With one or more of the meteorological monitoring channels inoperable for more than 7 days, prepare and submit a Special Report to the Commission, pursuant to Specification 6.7.3.C within the next 10 days outlining the cause of the malfunction and the plans for restoring the system to operable status.

4.2.I Meteorological Monitoring Instrumentation

Each meteorological monitoring instrument channel shall be demonstrated operable by the performance of the CHANNEL CHECK at least once per 24 hours and the CHANNEL CALIBRATION at least once each 6 months.

TABLE 3.2.A

PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Minimum No. Instrument Channels Operable per Trip Sys(1)(11)	Function	Trip Level Setting	Action (1)	Remarks
2	Instrument Channel - Reactor Low Water Level (6)	≥ 538" above vessel zero	A or (B and E)	1. Below trip setting does the following: a. Initiates Reactor Building Isolation b. Initiates Primary Containment Isolation c. Initiates SGTS
1	Instrument Channel - Reactor High Pressure	100 ± 15 psig	D	1. Above trip setting isolates the shutdown cooling suction valves of the RHR system.
2	Instrument Channel - Reactor Low Water Level (LIS-3-56A-D, SW #1)	≥ 470" above vessel zero	A	1. Below trip setting initiates Main Steam Line Isolation
2	Instrument Channel - High Drywell Pressure (6) (PS-64-56A-D)	≤ 2.5 psig	A or (B and E)	1. Above trip setting does the following: a. Initiates Reactor Building Isolation b. Initiates Primary Containment Isolation c. Initiates SGTS
2	Instrument Channel - High Radiation Main Steam Line Tunnel (6)	≤ 3 times normal rated full power background	B	1. Above trip setting initiates Main Steam Line Isolation
2	Instrument Channel - Low Pressure Main Steam Line	≥ 825 psig (4)	B	1. Below trip setting initiates Main Steam Line Isolation
2 (3)	Instrument Channel - High Flow Main Steam Line	≤ 140% of rated steam flow	B	1. Above trip setting initiates Main Steam Line Isolation

TABLE 3.2.A (Continued)

Minimum No. Instrument Channels Operable per Trip Sys(1)(11)	Function	Trip Level Setting	Action (1)	Remarks
2(12)	Instrument Channel - Main Steam Line Tunnel High Temperature	≤ 200°F	B	1. Above trip setting initiates Main Steam Line Isolation
2	Instrument Channel - Reactor Water Cleanup System Floor Drain High Temperature	160 - 180°F	C	1. Above trip setting initiates Isolation of Reactor Water Cleanup Line from Reactor and Reactor Water Return Line.
2	Instrument Channel - Reactor Water Cleanup System Space High Temperature	160 - 180°F	C	1. Same as above
1	Instrument Channel - Reactor Building Ventilation High Radiation - Reactor Zone	≤ 100 mr/hr or downscale	G	1. 1 upscale or 2 downscale will a. Initiate SGTS b. Isolate reactor zone and refuleing floor. c. Close atmosphere control system.
1	Instrument Channel - Reactor Building Ventilation High Radiation Refuleing Zone	≤ 100 mr/hr or downscale	F	1. 1 upscale or 2 downscale will a. Initiate SGTS. b. Isolate refueling floor. c. Close atmosphere control system.
2 (7)(8)	Instrument Channel SGTS Flow - Train A Heaters	Charcoal Heaters ≤ 2000 cfm R. H. Heaters ≤ 2000 cfm	H and (A or F)	1. Below 2000 cfm, trip setting charcoal heaters will turn on. 2. Below 2000 cfm, trip setting R. H. heaters will shut off.
2 (7)(8)	Instrument Channel SGTS Flow - Train B Heaters	Charcoal Heaters ≤ 2000 cfm R.H. Heaters ≤ 2000 cfm	H and (A or F)	1. Below 2000 cfm, trip setting charcoal heaters will turn on. 2. Below 2000 cfm, trip setting R.H. heaters will shut off.
2 (7)(8)	Instrument Channel SGTS Flow - Train C Heaters	Charcoal Heaters ≤ 2000 cfm R.H. Heaters ≤ 2000 cfm	H and (A or F)	1. Below 2000 cfm, trip setting charcoal heaters will turn on. 2. Below 2000 cfm, trip setting R.H. heaters will shut off.

TABLE 3.2.A (Continued)

Minimum No. Instrument Channels Operable per Trip Sys(1)(11)	Function	Trip Level Setting	Action (1)	Remarks
1	Reactor Building Isolation Timer (refueling floor)	$0 \leq t \leq 2$ secs.	H or F	1. Below trip setting prevents spurious trips and system perturbations from initiating isolation
1	Instrument Channel - Static Pressure Control Permissive (refueling floor)	N/A	H or F	1. Located in unit 1 only 2. Permissive for static pressure control (SGTS A, B, or C on). Channel shared by permissive on reactor zone static pressure cont.
1	Static Pressure Control Pressure Regulator (Refueling Floor)	$\leq 1/2''$ H_2O	H or F	1. Located in unit 1 only 2. Controls static pressure of refueling floor during reactor building isolation with SGTS running
1	Reactor Building Isolation Timer (reactor zone)	$0 \leq t \leq 2$ secs.	G or A or H	1. Below trip setting prevents spurious trips and system perturbations from initiating isolation
1(9)	Instrument Channel - Static Pressure Control Permissive (reactor zone)	N/A	I	1. Permissive for static pressure control (SGTS A, B, or C on). Channel shared by permissive on refueling floor static pressure control.
1(9)	Static Pressure Control Pressure Regulator (reactor zone)	$\leq 1/2''$ H_2O	I	1. Controls static pressure of reactor zone during reactor building isolation with SGTS running.
2(10)	Group 1 (Initiating) Logic	N/A	A	1. Refer to Table 3.7.A for list of valves.
1	Group 1 (Actuation) Logic	N/A	B	1. Refer to Table 3.7.A for list of valves.

TABLE 3.2.A (Continued)

Minimum No. Instrument Channels Operable per Trip Sys(1)(11)	Function	Trip Level Setting	Action (1)	Remarks
2	Group 2 (Initiating) Logic	N/A	A or (B and E)	1. Refer to Table 3.7.A for list of valves.
1	Group 2 (RHR Isolation-Actuation) Logic	N/A	D	
1	Group 2 (Tip-Actuation) Logic	N/A	J	
1	Group 2 (Drywell Sump Drains-Actuation) Logic	N/A	K	
1	Group 2 (Reactor Building & Refueling Floor, and Drywell Vent and Purge-Actuation) Logic	N/A	F and G	1. Part of Group 6 Logic
2	Group 3 (Initiating) Logic	N/A	C	1. Refer to Table 3.7.A for list of valves.
1	Group 3 (Actuation) Logic	N/A	C	
1	Group 6 Logic	N/A	F and G	1. Refer to Table 3.7.A for list of valves.
1	Group 8 (Initiating) Logic	N/A	J	1. Refer to Table 3.7.A for list of valves.
				2. Same as Group 2 initiating logic
1	Reactor Building Isolation (refueling floor) Logic	N/A	H or F	1. Logic has permissive to refueling floor static pressure regulator.
1	Reactor Building Isolation (reactor zone) Logic	N/A	H or G or A	1. Logic has permissive to reactor zone static pressure regulator.

TABLE 3.2.A

PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Minimum No. Instrument Channels Operable per Trip Sys(1)(11)	Function	Trip Level Setting	Action (1)	Remarks
1(7)(8)	SGTS Train A Logic	N/A	L or (A and F)	
1(7)(8)	SGTS Train B Logic	N/A	L or (A and F)	
1(7)(8)	SGTS Train C Logic	N/A	L or (A and F)	
1	Static Pressure Control (refueling floor) Logic	N/A	H or F	1. Located in unit 1 only.
1(9)	Static Pressure Control (reactor zone) Logic	N/A	I	

Refer to Table 3.2.B for RCIC and HPCI functions including Groups 4, 5, and 7 valves.

NOTES FOR TABLE 3.2.A

1. Whenever the respective functions are required to be operable, there shall be two operable or tripped trip systems for each function.

   If the first column cannot be met for one of the trip systems, that trip system or logic for that function shall be tripped (or the appropriate action listed below shall be taken). If the column cannot be met for all trip systems, the appropriate action listed below shall be taken.

   A. Initiate an orderly shutdown and have the reactors in Cold Shutdown Condition in 24 hours.

   B. Initiate an orderly load reduction and have Main Steam Lines isolated within eight hours.

   C. Isolate Reactor Water Cleanup System.

   D. Isolate Shutdown Cooling

   E. Initiate primary containment isolation within 24 hours.

   F. The handling of spent fuel will be prohibited and all operations over spent fuels and open reactor wells shall be prohibited.

   G. Isolate the reactor building and start the standby gas treatment system.

   H. Immediately perform a logic system functional test on the logic in the other trip systemsand daily thereafter not to exceed 7 days.

   I. No action required. Reactor zone walls and ceiling designed above suction pressure of the SGTS.

   J. Withdraw TIP.

   K. Manually isolate the affected lines. Refer to section 4.2.E for the requirements of an inoperable system.

   L. If one SGTS train is inoperable take actions H or action A and F. If two SGTS trains are inoperable take actions A and F.

2. When it is determined that a channel is failed in the unsafe condition, the other channels that monitor the same variable shall be functionally tested immediately before the trip system or logic for that function is tripped. The trip system or the logic for that function may remain untripped for short periods of time to allow functional testing of the other trip system or logic for that function.

3. There are four sensors per steam line of which two must be operable.

4. Only required in Run Mode (interlocked with Mode Switch).

5. Not required in Run Mode (bypassed by mode switch).

6. Channel shared by RPS and Primary Containment & Reactor Vessel Isolation Control System. A channel failure may be a channel failure in each system.

7. A train is considered a trip system.

8. Two out of three SGTS trains required. A failure of more than one will require action A and F.

9. There is only one trip system with auto transfer to two power sources.

10. Refer to Table 3.7.A and its notes for a listing of Isolation Valve Groups and their initiating signals.

11. A channel may be placed in an inoperable status for up to four hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

12. A channel contains four sensors, all of which must be operable for the channel to be operable.

NOTES FOR TABLE 3.2.C

1. For the startup and run positions of the Reactor Mode Selector Switch, there shall be two operable or tripped trip systems for each function. The SRM, IRM, and APRM (Startup mode), blocks need not be operable in "Run" mode, and the APRM (Flow biased) and RBM rod blocks need not be operable in "Startup" mode. If the first column cannot be met for one of the two trip systems, this condition may exist for up to seven days provided that during that time the operable system is functionally tested immediately and daily thereafter; if this condition last longer than seven days, the system with the inoperable channel shall be tripped. If the first column cannot be met for both trip systems, both trip systems shall be tripped.

2. W is the recirculation loop flow in percent of design. Trip level setting is in percent of rated power (3293 MWt).

   A ratio of FRP/CMFLPD<1.0 is permitted at reduced power. See Specification 2.1 for APRM control rod block setpoint.

3. IRM downscale is bypassed when it is on its lowest range.

4. SRM's A and C downscale function is bypassed when IRM's A, C, E, and G are above range 2. SRM's B and D downscale function is bypassed when IRM's B, D, F, and H are above range 2.

   SRM detector not in startup position is bypassed when the count rate is $\geq$ 100 CPS or the above condition is satisfied.

5. One instrument channel; i.e., one APRM or IRM or RBM, per trip system may be bypassed except only one of four SRM may be bypassed. Refer to Section 3.10.B for SRM requirements during core alterations.

6. IRM channels A, E, C, G all in range 8 bypasses SRM channels A & C functions.

   IRM channels B, F, D, H all in range 8 bypasses SRM channels B & D functions.

7. The following operational restraints apply to the RBM only.

   a. Both RBM channels are bypassed when reactor power is $\leq$ 30%.

   b. The RBM need not be operable in the "startup" position of the reactor mode selector switch.

   c. Two RBM channels are provided and only one of these may be bypassed from the console. An RBM channel may be out of service for testing and/or maintenance provided this condition does not last longer than 24 hours in any thirty day period.

   d. If minimum conditions for Table 3.2.C are not met, administrative controls, shall be immediately imposed to prevent control rod withdrawal.

TABLE 3.2.F
SURVEILLANCE INSTRUMENTATION

Minimum # of Operable Instrument Channels	Instrument #	Instrument	Type Indication and Range	Notes
2	LI-3-46 A LI-3-46 B	Reactor Water Level	Indicator - 155" to +60"	(1) (2) (3)
2	PI-3-54 PI-3-61	Reactor Pressure	Indicator 0-1200 psig	(1) (2) (3)
2	PR-64-50 PI-64-67	Drywell Pressure	Recorder 0-80 psia Indicator 0-80 psia	(1) (2) (3)
2	TI-64-52 TR-64-52	Drywell Temperature	Recorder, Indicator 0-400°F	(1) (2) (3)
1	TR-64-52	Suppression Chamber Air Temperature	Recorder 0-400°F	(1) (2) (3)
2	TI-64-55 TIS-64-55	Suppression Chamber Water Temperature	Indicator, 0-400°F	(1) (2) (3)
2	LI-64-54 A LI-64-66	Suppression Chamber Water Level	Indicator -25" to +25"	(1) (2) (3)
1	N/A	Control Rod Position	6V Indicating Lights	(1) (2) (3) (4)
1	N/A	Neutron Monitoring	SRM, IRM, LPRM 0 to 100% power	(1) (2) (3) (4)
1	PS-64-67	Drywell Pressure	Alarm at 35 psig	(1) (2) (3) (4)
1	TR-64-52 and PS-64-58 B and IS-64-67	Drywell Temperature and Pressure and Timer	Alarm if temp. > 281°F and pressure > 2.5 psig after 30 minute delay	(1) (2) (3) (4)
1	LI-84-2A	CAD Tank "A" Level	Indicator 0 to 100%	(1)
1	LI-84-13A	CAD Tank "B" Level	Indicator 0 to 100%	(1)

TABLE 4.2.A

SURVEILLANCE REQUIREMENTS FOR PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Function	Functional Test	Calibration Frequency	Instrument Check
Group 1 (Initiating) Logic	Checked during channel functional test. No further test required. (11)	N/A	N/A
Group 1 (Actuation) Logic	once/operating cycle (21)	N/A	N/A
Group 2 (Initiating) Logic	Checked during channel functional test. No further test required.	N/A	N/A
Group 2 (RHR Isolation-Actuation) Logic	once/operating cycle (21)	N/A	N/A
Group 8 (Tip-Actuation) Logic	once/operating cycle (21)	N/A	N/A
Group 2 (Drywell Sump Drains-Actuation) Logic	once/operating cycle (21)	N/A	N/A
Group 2 (Reactor Building and Refueling floor, and Drywell Vent and Purge-Actuation) Logic	once/operating cycle (21)	N/A	N/A
Group 3 (Initiating) Logic	Checked during channel functional test. No further test required.	N/A	N/A
Group 3 (Actuation) Logic	once/operating cycle (21)	N/A	N/A

3.3.A REACTIVITY CONTROLS

c. Control rods with scram times greater than those permitted by Specification 3.3.C.3 are inoperable, but if they can be inserted with control rod drive pressure they need not be disarmed electrically.

d. Control rods with a failed "Full-in" or "Full-out" position switch may be bypassed in the Rod Sequence Control System and considered operable if the actual rod position is known. These rods must be moved in sequence to their correct positions (full in on insertion or full out on withdrawal).

e. Control rods with inoperable accumulators or those whose position cannot be positively determined shall be considered inoperable.

f. Inoperable control rods shall be positioned such that Specification 3.3.A.1 is met. In addition, during reactor power operation, no more than one control rod in any 5 x 5 array may be inoperable (at least 4 operable control rods must separate any 2 inoperable ones). If this Specification cannot be met the reactor shall not be started, or if at power, the reactor shall be brought to a shutdown condition within 24 hours.

B. Control Rods

1. Each control rod shall be coupled to its drive or completely inserted and the

4.3.A REACTIVITY CONTROLS

b. A second licensed operator shall verify the conformance to Specification 3.3.A.2.d before a rod may be bypassed in the Rod Sequence Control System.

c. When it is initially determined that a control rod is incapable of normal insertion a test shall be conducted to demonstrate that the cause of the malfunction is not a failure in the control rod drive mechanism. If this can be demonstrated an attempt to fully insert the control rod shall be made. If the control rod cannot be inserted and an investigation has demonstrated that the cause of failure is not a failed control rod drive mechanism collet housing, a shutdown margin test shall be made to demonstrate under this condition that the core can be made subcritical for any reactivity condition during the remainder of the operating cycle with the analytically determined highest worth control rod capable of withdrawal fully withdrawn, and all other control rods capable of insertion fully inserted.

d. The control rod accumulators shall be determined operable at least once per 7 days by verifying that the pressure and level detectors are not in the alarmed condition.

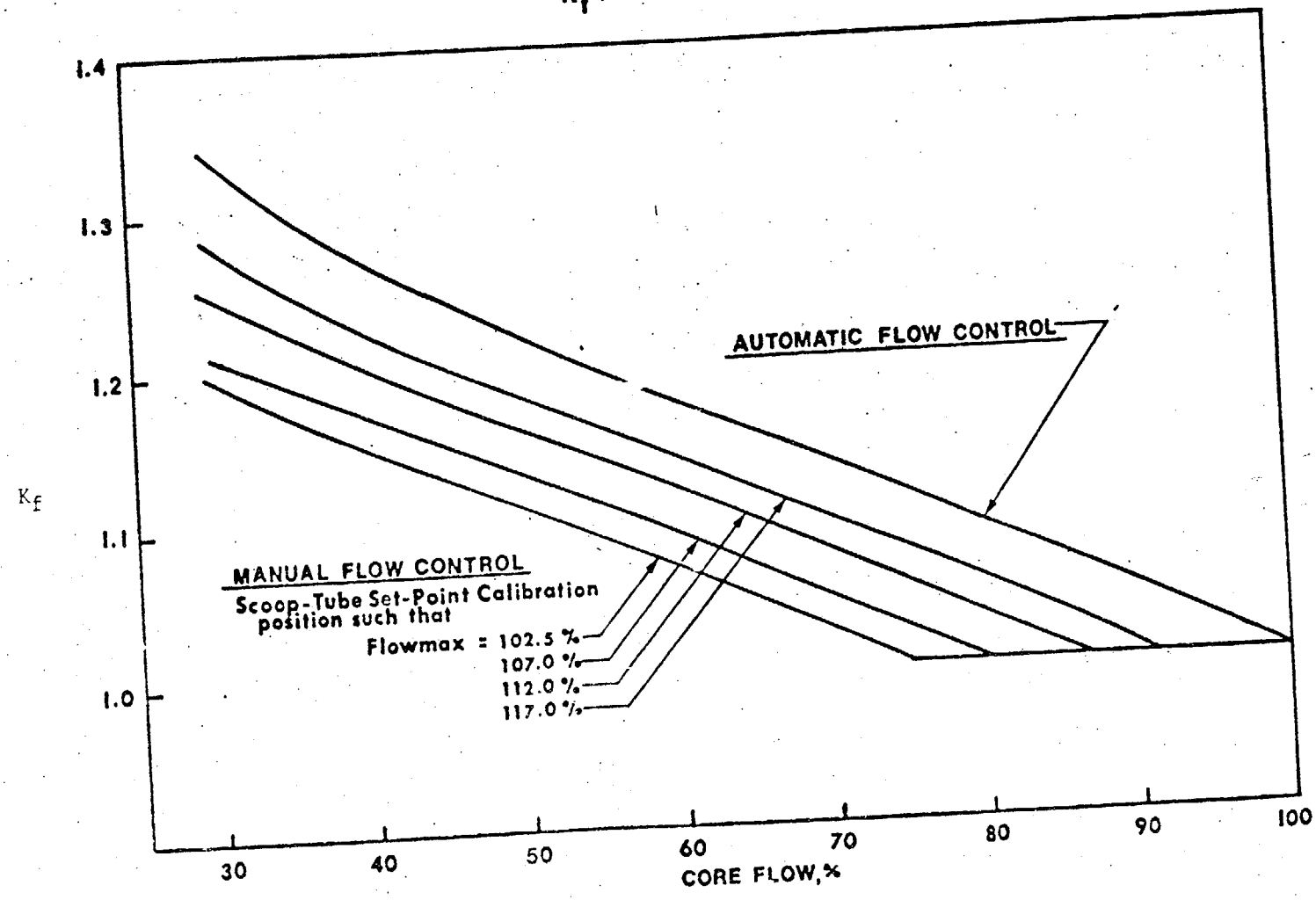
B. CONTROL RODS

1. The coupling integrity shall be verified for each withdrawn control rod as follows:

BROWNS FERRY NUCLEAR PLANT

FIGURE 3.5.2

K_f FACTOR



3.6.A Thermal and Pressurization Limitations

3. During heatup by non-nuclear means, except when the vessel is vented or as indicated in 3.6.A.4, during cooldown following nuclear shutdown, or during low-level physics tests, the reactor vessel temperature shall be at or above the temperatures of curve #2 of Figure 3.6.1 until removing tension on the head stud bolts as specified in 3.6.A.5.

4. The reactor vessel shell temperatures during inservice hydrostatic or leak testing shall be at or above the temperatures shown on curve #1 of figure 3.6-1. The applicability of this curve to these tests is extended to non-nuclear heatup and ambient loss cooldown associated with these tests only if the heatup and cooldown rates do not exceed 15°F per hour.

5. The reactor vessel head bolting studs may be partially tensioned (four sequences of the seating pass) provided the studs and flange materials are above 70°F. Before loading the flanges any more, the vessel flange and head flange must be greater than 100°F, and must remain above 100°F while under full tension.

6. The pump in an idle recirculation loop shall not be started unless the temperatures of the coolant within the idle and operating recirculation loops are within 50°F of each other.

7. The reactor recirculation pumps shall not be started unless the coolant temperatures between the dome and the bottom head drain are within 145°F.

4.6.A Thermal and Pressurization Limitations

3. Test specimens representing the reactor vessel, base weld and weld heat affected zone metal shall be installed in the reactor vessel adjacent to the vessel wall at the core midplane level. The number and type of specimens will be in accordance with GE report NEDO-10115. The specimens shall meet the intent of ASTM E 185-70. Samples shall be withdrawn at one-fourth and three-fourths service life.

4. Neutron flux wires shall be installed in the reactor vessel adjacent to the reactor vessel wall at the core midplane level. The wires shall be removed and tested during the first refueling outage to experimentally verify the calculated values of neutron fluence at one-fourth of the beltline shell thickness that are used to determine the NDT shift from Figure 3.6-2.

5. When the reactor vessel head bolting studs are tensioned and the reactor is in a cold condition, the reactor vessel shell temperature immediately below the head flange shall be permanently recorded.

6. Prior to and during startup of an idle recirculation loop, the temperature of the reactor coolant in the operating and idle loops shall be permanently logged.

7. Prior to starting a recirculation pump, the reactor coolant temperatures in the dome and in the bottom head drain shall be compared and permanently logged.

3.6 PRIMARY SYSTEM BOUNDARY

C. Coolant Leakage

1. Any time irradiated fuel is in the reactor vessel and reactor coolant temperature is above 212°F, reactor coolant leakage into the primary containment from unidentified sources shall not exceed 5 gpm. In addition, the total reactor coolant system leakage into the primary containment shall not exceed 25 gpm.

2. Both the sump and air sampling systems shall be operable during reactor power operation. From and after the date that one of these systems is made or found to be inoperable for any reason, reactor power operation is permissible only during the succeeding seven days.

   The air sampling system may be removed from service for a period of 4 hours for calibration, functional testing, and maintenance without providing a temporary monitor.

4.6 PRIMARY SYSTEM BOUNDARY

C. Coolant Leakage

1. Reactor coolant system leakage shall be checked by the sump and air sampling system and recorded at least once per day.

2. With the air sampling system inoperable, grab samples shall be obtained and analyzed at least once every 24 hours.

3.6.F Jet Pump Flow Mismatch

1. The reactor shall not be operated with one recirculation loop out of service for more than 24 hours. With the reactor operating, if one recirculation loop is out of service, the plant shall be placed in a hot shutdown condition within 24 hours unless the loop is sooner returned to service.

2. Following one pump operation, the discharge valve of the low speed pump may not be opened unless the speed of the faster pump is less than 50% of its rated speed.

3. Steady state operation with both recirculation pumps out of service for up to 12 hrs is permitted. During such interval restart of the recirculation pumps is permitted, provided the loop discharge temperature is within 75°F of the saturation temperature of the reactor vessel water as determined by dome pressure. The total elapsed time in natural circulation and one pump operation must be no greater than 24 hrs.

G. Structural Integrity

1. The structural integrity of the primary system shall be

4.6.E Jet Pumps

b. The indicated value of core flow rate varies from the value derived from loop flow measurements by more than 10%.

c. The diffuser to lower plenum differential pressure reading on an individual jet pump varies from the mean of all jet pump differential pressures by more than 10%.

2. Whenever there is recirculation flow with the reactor in the Startup or Run Mode and one recirculation pump is operating with the equalizer valve closed, the diffuser to lower plenum differential pressure shall be checked daily and the differential pressure of an individual jet pump in a loop shall not vary from the mean of all jet pump differential pressures in that loop by more than 10%.

F. Recirculation Pump Operation

1. Recirculation pump speeds shall be checked and logged at least once per day.

2. No additional surveillance required.

3. Before starting either recirculation pump during steady state operation, check and log the loop discharge temperature and dome saturation temperature.

G. Structural Integrity

1. Table 4.6.A together with supplementary notes, spec

3.7.A Primary Containment

c. Two drywell-suppression chamber vacuum breakers may be determined to be inoperable for opening.

d. If specifications 3.7.A.4.a, .b, or .c cannot be met, the unit shall be placed in a cold shutdown condition in an orderly manner within 24 hours.

5. Oxygen Concentration

a. After completion of the fire-related startup retesting program, containment atmosphere shall be reduced to less than 4% oxygen with nitrogen gas during reactor power operation with reactor coolant pressure above 100 psig, except as specified in 3.7.A.5.b.

b. Within the 24-hour period subsequent to placing the reactor in the Run mode following a shutdown, the containment atmosphere oxygen concentration shall be reduced to less than 4% by volume and maintained in this condition. De-inerting may commence 24 hours prior to a shutdown.

c. If specification 3.7.A.5.a and 3.7.A.5.b cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a Cold Shutdown condition within 24 hours.

4.7.A Primary Containment

valves shall be exercised immediately and every 15 days thereafter until the inoperable valve has been returned to normal service.

c. Once each operating cycle each vacuum breaker valve shall be inspected for proper operation of the valve and limit switches.

d. A leak test of the drywell to suppression chamber structure shall be conducted during each operating cycle. Acceptable leak rate is 0.14 lb/sec of primary containment atmosphere with 1 psi differential.

5. Oxygen Concentration

a. The primary containment oxygen concentration shall be measures and recorded daily. The oxygen measurement shall be adjusted to account for the uncertainty of the method used by adding a predetermined error function.

b. The methods used to measure the primary containment oxygen concentration shall be calibrated once every refueling cycle.

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
3	Reactor water cleanup system supply isolation valves FCV-69-1, & 2	1	1	30	0	GC
3	Reactor water cleanup system return isolation valves FCV-69-12		1	60	0	GC
4	FCV 73-81 (Bypass around FCV 73-3)		1	10	0	GC
4	HPCIS steamline isolation valves FCV-73-2 & 3	1	1	20	0	GC
5	RCICS steamline isolation valves FCV-71-2 & 3	1	1	15	0	GC
6	Drywell nitrogen purge inlet isolation valves (FCV-76-18)		1	10	C	SC
6	Suppression chamber nitrogen purge inlet isolation valves (FCV-76-19)		1	10	C	SC
6	Drywell Main Exhaust isolation valves (FCV-64-29 and 30)		2	90	C	SC
6	Suppression chamber main exhaust isolation valves (FCV-64-32 and 33)		2	90	C	SC
6	Drywell/Suppression Chamber purge inlet (FCV-64-17)		1	90	C	SC
6	Drywell Atmosphere purge inlet (FCV-64-18)		1	90	C	SC

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
6	Torus Hydrogen Sample Line Valves Analyzer A (FSV-76-55, 56)	1	1	NA	Note 1	SC
6	Torus Oxygen Sample Line Valves Analyzer A (FSV-76-53, 54)	1	1	NA	Note 1	SC
6	Drywell Hydrogen Sample Line Valves Analyzer A (FSV-76-49, 50)	1	1	NA	Note 1	SC
6	Drywell Oxygen Sample Line Valves Analyzer A (FSV-76-51, 52)	1	1	NA	Note 1	SC
6	Sample Return Valves - Analyzer A (FSV-76-57, 58)	1	1	NA	0	GC
6	Torus Hydrogen Sample Line Valves Analyzer B (FSV-76-65, 66)	1	1	NA	Note 1	SC
6	Torus Oxygen Sample Line Valves-Analyzer B (FSV-76-63, 64)	1	1	NA	Note 1	SC
6	Drywell Hydrogen Sample Line Valves-Analyzer B (FSV-76-59, 60)	1	1	NA	Note 1	SC
6	Drywell Oxygen Sample Line Valves-Analyzer B (FSV-76-61, 62)	1	1	NA	Note 1	SC
6	Sample Return Valves-Analyzer B (FSV-76-67, 68)	1	1	NA	0	GC

Note 1: Analyzers are such that one is sampling drywell hydrogen and oxygen (valves from drywell open-valves from torus closed) while the other is sampling torus hydrogen and oxygen (valves from torus open - valves from drywell closed)

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
6	Suppression Chamber purge inlet (FCV-64-19)		1	100	C	SC
6	Drywell/Suppression Chamber nitrogen purge inlet (FCV-76-17)		1	10	C	SC
6	Drywell Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-31)		1	10	C	SC
6	Suppression Chamber Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-34)		1	10	C	SC
6	System Suction Isolation Valves to Air Compressors "A" and "B" (FCV-32-62, 63)		2	15	0	GC
7	RCIC Steamline Drain (FCV-71-6A, 6B)		2	5	0	GC
7	RCIC Condensate Pump Drain (FCV-71-7A, 7B)		2	5	0	GC
7	HPCI Hotwell pump discharge isolation valves (FCV-73-17A, 17B)		2	5	C	SC
7	HPCI steamline drain (FCV-75-57, 58)		2	5	0	GC
8	TIP Guide Tubes (5)		1 per guide tube	NA	C	GC

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
43-28B	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-226 and 43-28B
43-29A	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-227 and 43-29A
43-29B	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-227 and 43-29B
64-17	Drywell and Suppression Chamber air purge inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
64-18	Drywell air purge inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
64-19	Suppression Chamber air purge inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
64-20	Suppression Chamber vacuum relief	Air(1)	Applied between 64-20 and 64-(ck)
64-(ck)	Suppression Chamber vacuum relief	Air(1)	Applied between 64-20 and 64-(ck)
64-21	Suppression Chamber vacuum relief	Air(1)	Applied between 64-21 and 64-(ck)
64-(ck)	Suppression Chamber vacuum relief	Air(1)	Applied between 64-21 and 64-(ck)
64-29	Drywell main exhaust	Air(1)	Applied between 64-29, 64-30, 64-32 64-33 and 84-19
64-30	Drywell main exhaust	Air(1)	Applied between 64-29, 64-30, 64-32, 64-33 and 84-19
64-31	Drywell exhaust to Standby	Air(1)	Applied between 64-31, 64-141, 84-20 and 64-140
64-32	Suppression Chamber Main Exhaust	Air(1)	Applied between 64-32, 64-33, 64-29, 64-30 and 84-19
64-33	Suppression Chamber Main Exhaust	Air(1)	Applied between 64-32, 64-33, 64-29, 64-30 and 84-19
64-34	Suppression Chamber to Standby Gas Treatment	Air(1)	Applied between 64-34, 64-141 and 64-139
68-508	CRD to RC Pump Seals	Air(1)	Applied between 68-507 and 68-508
68-523	CRD to RC Pump Seals	Air(1)	Applied between 68-522 and 68-523
68-550	CRD to RC Pump Seals	Air(1)	Applied between 68-507 and 68-550
68-555	CRD to RC Pump Seals	Air(1)	Applied between 68-522 and 68-555

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
69-1	RWCU Supply	Water (2)	Applied between 69-1, 69-500 and 10-505
69-2	RWCU Supply	Water (2)	Applied between 69-2, 69-500 and 10-505
71-2	RCIC Steam Supply	Air (1)	Applied between 71-2 and 71-3
73-81	HPCI Steam Supply Bypass	Air (1)	Applied between 73-2 and 73-3
71-3	RCIC Steam Supply	Air (1)	Applied between 71-2 and 71-3
71-39	RCIC Pump Discharge	Water (2)	Applied between 3-66, 3-568, 69-579, 71-39, and 85-576
73-2	HPCI Steam Supply	Air (1)	Applied between 73-2 and 73-3
73-3	HPCI Steam Supply	Air (1)	Applied between 73-2 and 73-3
73-44	HPCI Pump Discharge	Water (2)	Applied between 3-67, 3-554, and 73-44
74-47	RHR Shutdown Suction	Water (2)	Applied between 74-47, 74-754, 74-49, and 74-661
74-48	RHR Shutdown Suction	Water (2)	Applied between 74-48, 74-661, and 74-49
74-53	RHR LPCI Discharge	Water (2)	Applied between 74-53 and 74-55
74-57	RHR Suppression Chamber Spray	Water (2)	Applied between 74-57, 75-53, and 74-59
74-58	RHR Suppression Chamber Spray	Water (2)	Applied between 74-57, 74-58, and 74-59
74-60	RHR Drywell Spray	Water (2)	Applied between 74-60, 74-61
74-61	RHR Drywell Spray	Water (2)	Applied between 74-60, 74-61
74-67	RHR LPCI Discharge	Water (2)	Applied between 74-67 and 74-69
74-71	RHR Suppression Chamber Spray	Water (2)	Applied between 74-71, 74-72, and 74-73
74-72	RHR Suppression Chamber Spray	Water (2)	Applied between 74-71, 74-72, and 74-73
74-74	RHR Drywell Spray	Water (2)	Applied between 74-74, 74-75

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
76-49	Containment Inerting	Air	Applied between inboard block valve and 76-49.
76-50	Containment Inerting	Air	Applied between inboard block valve and 76-50.
76-51	Containment Inerting	Air	Applied between inboard block valve and 76-51.
76-52	Containment Inerting	Air	Applied between inboard block valve and 76-52.
76-53	Containment Inerting	Air	Applied between inboard block valve and 76-53.
76-54	Containment Inerting	Air	Applied between inboard block valve and 76-54.
76-55	Containment Inerting	Air	Applied between inboard block valve and 76-55.
76-56	Containment Inerting	Air	Applied between inboard block valve and 76-56.
76-57	Containment Inerting	Air	Applied between inboard block valve and 76-57.
76-58	Containment Inerting	Air	Applied between inboard block valve and 76-58.
76-59	Containment Inerting	Air	Applied between inboard block valve and 76-59.
76-60	Containment Inerting	Air	Applied between inboard block valve and 76-60.
76-61	Containment Inerting	Air	Applied between inboard block valve and 76-61.
76-62	Containment Inerting	Air	Applied between inboard block valve and 76-62.
76-63	Containment Inerting	Air	Applied between inboard block valve and 76-63.
76-64	Containment Inerting	Air	Applied between inboard block valve and 76-64.
76-65	Containment Inerting	Air	Applied between inboard block valve and 76-65.
76-66	Containment Inerting	Air	Applied between inboard block valve and 76-66.
76-67	Containment Inerting	Air	Applied between inboard block valve and 76-67.
76-68	Containment Inerting	Air	Applied between inboard block valve and 76-68.

Amendment No. 82

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
90-237A	Radiation Monitor Discharge	Air(1)	Applied between 90-237A and 90-237B
90-237B	Radiation Monitor Discharge	Air(1)	Applied between 90-237A and 90-237B
84-8A	Containment Atmospheric Dilution	Air	Applied between 84-8A and 84-600
84-8B	Containment Atmospheric Dilution	Air	Applied between 84-8B and 84-601
84-8C	Containment Atmospheric Dilution	Air	Applied between 84-8C and 84-603
84-8D	Containment Atmospheric Dilution	Air	Applied between 84-8D and 84-602
84-19	Containment Atmospheric Dilution	Air	Applied between 64-32, 64-33, 64-29, 64-30, and 84-19

(1) Air/nitrogen test to be displacement flow.
(2) Water test to be injection loss or downstream collection.

Valves	Valve Identification	Test Medium	Test Method
84-20	Main Exhaust to Standby Gas Treatment	Air(1)	Applied between 84-20, 64-141, 64-140, and 64-31
84-600	Main Exhaust to Standby Gas Treatment	Nitrogen(1)	Applied between 84-8A and 84-600
84-601	Main Exhaust to Standby Gas Treatment	Nitrogen	Applied between 84-8B and 84-601
84-602	Main Exhaust to Standby Gas Treatment	Nitrogen	Applied between 84-8C and 84-603
84-603	Main Exhaust to Standby Gas Treatment	Nitrogen	Applied between 84-8D and 84-602
64-141	Drywell Pressurization, Comp. Bypass	Air (1)	Applied between 64-141, 64-140, 64-30, and 84-20
64-140	Drywell Pressurization, Comp. Disc.	Air(1)	Applied between 64-141, 64-140, 64-31, and 84-20
64-139	Drywell Pressurization, Comp. Suction	Air(1)	Applied between 64-139, 64-141, and 64-34

(1) Air/nitrogen test to be displacement flow
(2) Water test to be injection loss or downstream collection.

3.9 AUXILIARY ELECTRICAL SYSTEM

b. The units 1 and 2 4-kV shutdown boards are energized.

c. The 480-V shutdown boards associated with the unit are energized.

d. The units 1 and 2 diesel auxiliary boards are energized.

e. Loss of voltage and degraded voltage relays operable on 4-kV shutdown boards A, B, C, and D.

f. Shutdown busses 1 and 2 energized.

5. The 250-volt unit and shutdown board batteries and a battery charger for each battery boards are operable.

6. Logic Systems

a. Common accident signal logic system is operable.

b. 480-V load shedding logic system is operable.

7. There shall be a minimum of 103,300 gallons of diesel fuel in the standby diesel generator fuel tanks.

4.9 AUXILIARY ELECTRICAL SYSTEM

with instructions based on the manufacturer's recommendations.

e. Once a month a sample of diesel fuel shall be checked for quality. The quality shall be within acceptable limits specified in Table 1 of the latest revision to ASTM D975 and logged.

2. D. C. Power System - Unit Batteries (250-Volt) Diesel Generator Batteries (125-Volt) and Shutdown Board Batteries (250-Volt)

a. Every week the specific gravity and the voltage of the pilot cell, and temperature of an adjacent cell and overall battery voltage shall be measured and logged.

b. Every three months the measurements shall be made of voltage of each cell to nearest 0.1 volt, specific gravity of each cell, and temperature of every fifth cell. These measurements shall be logged.

c. A battery rated discharge (capacity) test shall be performed and the voltage, time, and output current measurements shall be logged at intervals not to exceed 24 months.

3.10 CORE ALTERATIONS

Applicability

Applies to the fuel handling and core reactivity limitations.

Objective

To ensure that core reactivity is within the capability of the control rods and to prevent criticality during refueling.

Specification

A. Refueling Interlocks

1. The reactor mode switch shall be locked in the "Refuel" position during core alterations and the refueling interlocks shall be operable except as specified in 3.10.A.5 and 3.10.A.6 below.

2. Fuel shall not be loaded into the reactor core unless all control rods are fully inserted.

4.10 CORE ALTERATIONS

Applicability

Applies to the periodic testing of those interlocks and instrumentation used during refueling and core alterations.

Objective

To verify the operability of instrumentation and interlocks used in refueling and core alterations.

Specification

A. Refueling Interlocks

1. Prior to any fuel handling with the head off the reactor vessel, the refueling interlocks shall be functionally tested. They shall be tested at weekly intervals thereafter until no longer required. They shall also be tested following any repair work associated with the interlocks.

2. Prior to performing control rod or control rod drive maintenance on control cells without removing fuel assemblies, it shall be demonstrated that the core can be made subcritical by a margin of 0.38 percent $\Delta k/k$ at any time during the maintenance with the strongest operable control rod fully withdrawn and all other operable rods fully inserted. Alternatively if the remaining

3.11 FIRE PROTECTION SYSTEMS

B. CO_2 Fire Protection System

1. The CO_2 Fire Protection System shall be operable:

   a. With a minimum of 8-1/2 tons (0.5 Tank) CO_2 in storage units 1 and 2.

   b. With a minimum of 3 tons (0.5 Tank) CO_2 storage unit 3.

   c. Automatic initiation logic operable.

2. If specification 3.11.B.1.a or 3.11.B.1.b or 3.11.B.1.c cannot be met, a patrolling fire watch with portable fire equipment shall be established to ensure that each area where protection is lost is checked hourly.

3. If specifications 3.11.B.1.a, 3.11.B.1.b, or 3.11.B.1.c are not met within 7 days, the affected unit(s) shall be in cold shutdown within 24 hours.

4.11 FIRE PROTECTION SYSTEMS

B. CO_2 Fire Protection System

1. CO_2 Fire Protection Testing:

Item	Frequency
a. Simulated automatic and manual actuation	Once/year
b. Storage tank pressure and level	Checked daily
c. CO_2 Spray header and nozzle inspection for blockage	Once/3 years

2. When the cable spreading room CO_2 Fire Protection is inoperable, one 125-pound (or larger) portable fire extinguisher shall be placed at each entrance.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.10.A Refueling Interlocks	4.10.A Refueling Interlocks
	control rods are fully inserted and have had their directional control valves electrically disarmed, it is sufficient to demonstrate that the core is subcritical with a margin of at least 0.38 percent Δk/k any time during the maintenance. A control rod on which maintenance is being performed shall be considered inoperable.
3. The fuel grapple hoist load switch shall be set at ≤ 1,000 lbs.	3. No additional surveillance required.
4. If the frame-mounted auxiliary hoist, the monorail-mounted auxiliary hoist, or the service platform hoist is to be used for handling fuel with the head off the reactor vessel, the load limit switch on the hoist to be used shall be set at ≤ 400 lbs.	4. No additional surveillance required.
5. A maximum of two non-adjacent control rods may be withdrawn from the core for the purpose of performing control rod and/or control rod drive maintenance, provided the following conditions are satisfied:	5. No additional surveillance required.
a. The reactor mode switch shall be locked in the "refuel" position. The refueling interlock which prevents more than one control rod from being withdrawn may be bypassed for one of the control rods on which maintenance is being performed. All other	

B. Source Tests

Results of required leak tests performed on sources if the tests reveal the presence of 0.005 microcurie or more of removable contamination.

C. Special Reports (in writing to the Director of Regional Office of Inspection and Enforcement).

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

a.	Secondary Containment Leak Rate Testing(5)	4.7.C	Within 90 days of completion of each test.
b.	Fatigue Usage Evaluation	6.6	Annual Operating Report
c.	Seismic Instrumentation Inoperability	3.7.J.3	Within 10 days after 30 days of inoperability
d.	Relief Valve Tailpipe Instrumentation	3.2.F	Within 30 days after inoperability of thermocouple and acoustic monitor on one valve.
e.	Meteorological Monitoring Instrumentation Inoperability	3.2.I.2	Within 10 days after 7 days of inoperability

D. Special Report (in writing to the Director of Regional Office of Inspection and Enforcement)

Data shall be retrieved from all seismic instruments actuated during a seismic event and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be submitted within 10 days after the event describing the magnitude, frequency spectrum, and resultant effect upon plant features important to safety.

Meteorological data shall be summarized and reported consistent with the recommendations of Regulatory Guide 1.21 (June 1974) and Regulatory Guide 1.23 (February 1972), and meteorological observations shall be recorded in a form consistent with National Weather Service procedures.

If the outage of any meteorological instrument(s) required by Regulatory Guide 1.23 (February 1972) exceeds seven consecutive days, the total outage time, the dates of outage, the cause of the outage, and the instrument(s) involved shall be reported within 10 (1) days of the initiation of the outage to the USNRC, Office of Inspection and Enforcement, with a copy to the Office of Nuclear Reactor Regulation, Division of Operating Reactors. Elements of this program may be modified or terminated in accordance with Subsection 5.6.3(c).

The collection of meteorological data at the plant site provides information for use in developing atmospheric diffusion parameters for estimating potential radiation doses to the public resulting from actual routine or abnormal releases of radioactive materials to the atmosphere, and for assessing the actual impact of the plant cooling system on the atmospheric environment of the site area. A meteorological data collection program as described above is necessary to meet the requirements of subparagraph 50.36a(a)(2) of 10 CFR Part 50, Appendix D to 10 CFR Part 50, and Appendix E to 10 CFR Part 50.

(1) Ref. Section 6.7.3.D Appendix A Technical Specifications.

5.5.3 Written procedures described in Section 5.5.1 shall be reviewed by PORC and approved by the Power Plant Superintendent prior to implementation. Temporary changes to a procedure which do not change the intent of the approved procedure may be made by a member of the plant staff knowledgeable in the area affected by the procedure and the additional approval of a member of the plant staff who holds a Senior Reactor Operator License. Such changes shall be documented and subsequently reviewed by PORC and approved by the Power Plant Superintendent.

5.6 Reporting Requirements

5.6.1 A report shall be prepared by TVA and submitted to NRC following the end of each 12-month period of operation, which shall summarize the results of the nonradiological environmental monitoring program.

5.6.2 Routing Reporting

a. A summary report shall be prepared for both the inplant monitoring program and the nonradiological monitoring programs and submitted to the Director of Division of Operating Reactors, NRC, as part of the Annual Operating Report within 120 days after December 31 of each year.

b. Radiological Environmental Monitoring

Routine Reporting

Reporting Requirements:

1. TVA shall prepare a report entitled "Environmental Radioactivity Levels - Browns Ferry Nuclear Plant - Annual Report." The report shall cover the previous 12 months of operation and shall be submitted to the Director of the NRC Region II Office (with a copy to the Director, Office of Nuclear Reactor Regulation) within 120 days after January 1 of each year. The report format shown in Regulatory Guide 4.8 Title 1 shall be used. The report shall include summaries, interpretations, and evaluations of the results of the radiological environmental surveillance activities for the report period, including a comparison with preoperational studies and/or operational controls (as appropriate), and an assessment of the observed impacts of the plant operation on the environmenta. If harmful effects or evidence of irreversible damage are detected by the monitoring, the licensee shall provide an analysis of the problem and a proposed course of action to alleviate the problem.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 85 TO FACILITY OPERATING LICENSE NO. DPR-33

AMENDMENT NO. 82 TO FACILITY OPERATING LICENSE NO. DPR-52

AMENDMENT NO. 56 TO FACILITY OPERATING LICENSE NO. DPR-68

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT, UNIT NOS. 1, 2 AND 3

1.0 Introduction

By letter dated May 15, 1981 (TVA BFNP TS 162), and supplemented by letters dated June 16, 1981 and September 28, 1981, the Tennessee Valley Authority (the licensee or TVA) requested changes to the Technical Specifications Appendix A) appended to Facility Operating License Nos. DPR-33, DPR-52 and DPR-68 for the Browns Ferry Nuclear Plant, Unit Nos. 1, 2 and 3. The proposed amendments consist of clarification and administrative changes and reorganization of some sections of the Technical Specifications.

2.0 Evaluation

TVA's submittals of June 16 and September 28, 1981 contains a page-by-page discussion of each proposed change to the Technical Specifications. Most of the changes are administrative in nature (e.g., adding subtitles, reformating, etc.) In the following evaluation, the reference to page numbers is the page in the Browns Ferry Unit No. 1 (BF-1) Technical Specifications; for the corresponding numbers in the Unit Nos. 2 and 3 Technical Specifications, the reader is referred to the June 16 and September 28, 1981 submittals.

1. Sections 1.0 and 1.1 (pgs 8, 9, 10 and 11) - TVA is proposing to add three subtitles for the limits on these pages - a. Thermal Power Limits, b. Power Transient and c. Reactor Vessel Water Level. At present, the various Thermal-hydraulic limits are listed but not categorized. There is some relocation and relettering of limits to place them under the appropriate subtitles. There are no changes to any safety limits or limiting safety system settings. The proposed changes are acceptable.

2. Section 2.1.E Bases (pgs 23, 24, 34, 38, 40 and 44) - The changes proposed by TVA on these pages is to combine references to loss of turbine control oil pressure and turbine control valve fast closure and to rename 2.1.E as "Turbine Control Valve Fast Closure or Turbine Trip Scram". Loss of turbine control oil pressure and turbine control valve fast closure are both detected by the same instrument. Since there is actually only one instrument that senses either of the conditions, TVA proposes to combine what is now two paragraphs (2.1.E.1 and 2.1.E.2)

into one with a combined title. There is no change in the information in the bases or in any surveillance requirements. The proposed clarification change is acceptable.

3. Tables 3.1.A (pgs. 33 and 36) - Table 3.1.A lists the "Reactor Protection System Instrumentation Requirement". Besides listing the function, setting and action of each trip setting, the table lists the minimum number of operable instrument channels per trip system. TVA purposes to add an additional note to this table (note 23) to clarify that "a channel may be placed in an inoperable status for up to 4 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter." Periodic surveillance testing of these channels is required by the Technical Specifications. At present, the Technical Specifications are silent on whether the trip system is tripped during surveillance testing or how long the channel is inoperable. The wording by TVA is identical to that in note (a) for Table 3.3.1-1 ("Reactor Protection System Instrumentation") on page 3-5 of the BWR Standard Technical Specifications (NUREG-0123, Rev. 3) except for the time a channel may be inoperable. The Standard Technical Specifications state 2 hours whereas TVA is proposing 4 hours. We have discussed this difference with the TVA staff and reviewed the maintenance practices at Browns Ferry. The Standard Technical Specifications were written for later vintage plants than Browns Ferry. The Browns Ferry units do not have the test features that were incorporated in the later product lines. At Browns Ferry, most of the surveillance tests are completed in less than 2 hours. However, it is most important that the tests be performed in an orderly, thorough manner and there are occasions when the time elapsed from installation of jumpers to completion of the double sign-offs takes more than 2 hours. Our review indicated that even though there is at present no time limit, surveillance tests have been performed expeditiously; there was no indication that the technicians took longer than necessary. Safety is not adversely affected during these tests because reactor protection functions are still provided by the operable channel in the trip system being tested and by the other redundant trip system. For the reasons discussed above, we conclude that the proposed change is acceptable.

4. Table 4.1.B (p. 40) - Note 8 to this table specifies that the individual LPRM readings will be adjusted at the beginning of each operating cycle before reaching 100% power. However, the calibration requirement in the table on the IRM high flux where this note is referenced, states "comparison to APRM on controlled shutdowns". TVA proposes to change "shutdowns" to "startups", to conform with the requirement in note 6. Since the calibration is performed on startup to detect any discrepancies introduced by maintenance of the systems during the refueling outage, the proposed change is acceptable.

5. Table 3.2.A (pgs. 55, 56, 57, 58, 59 and 61) - This table lists the "Primary Containment and Reactor Building Isolation Instrument". TVA proposes to add a note (note 11) to this table similar to that proposed for table 3.1.A (item 3, above) to clarify that "a channel may be placed in an inoperable status for up to four hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter." The wording proposed by TVA is identical to that in note (b) to Table 3.3.2-1 ("Isolation Actuation Instrumentation") on page 3-14 of the BWR Standard Technical Specifications except that the later specifies 2 hours vs the 4 hours proposed by TVA. For the reasons discussed in item 3 above, we conclude that the time proposed by TVA is acceptable.

6. Table 3.2.F (p. 78) - This table lists the "Surveillance Instrumentation". TVA proposes to change the specified range on reactor water level instruments LI-3-46A and B from -107.5 in. to +107.5 in." to -155 in. to +60 in." to reflect the current plant instrumentation. The actual range covered by the instruments (i.e., a total of 215 inches) is not changed. The proposed revision is acceptable.

7. Section 4.3.A.c (p. 121) - TVA proposes to add a phrase to the first sentence of the surveillance requirements to require that "a test shall be conducted to demonstrate that the cause of the malfunction is not a failure in the control rod drive mechanism". This section discusses the actions to be taken if a control rod is incapable of normal insertion. The phrase alerts the operator to check the mechanism before attempting to again insert the control rod, since attempts to insert rods with failed collet housings could cause damage to the housings. The proposed change adds an additional surveillance requirement without reducing any of the other requirements. We conclude that the proposed change is acceptable.

8. Section 3.6.A.3 (p. 175) - This section specifies some of the thermal and pressurization limits during cooldown and low-level physics tests. TVA proposes to add a phrase at the end of sentence stating that the curves shall be followed "until removing tension on the head stud bolts as specified in 3.6.A.5". The change does not alter the requirements in this section other then to add additional guidance on how long the requirements must be maintained. The proposed change is acceptable.

9. Section 4.6.B (pgs. 176, 177, 178 and 179) - TVA proposed relaxation of the water chemistry sampling requirements. The proposed changes have not been sufficiently justified and are not approved and thus are not included in this amendment.

10. Section 4.6.C.2 (p. 180) - TVA proposes to add a sentence clarifying

that the containment "air sampling system may be temporarily removed from service for up to 4 hours for calibration, functional testing, and maintenance without providing a temporary monitor." The paragraph presently states that "both the sump and air sampling systems shall be operable during reactor power operation. From and after the date that one of these systems is made or found to be inoperable for any reason, reactor power operation is permissible only during the succeeding seven days." The surveillance requirements also require that "with the air sampling system inoperable, grab samples shall be obtained and analyzed at least once every 24 hours." The four hour time limit proposed by TVA is more limiting than the present requirements. Our review also indicates that on occasion, maintenance on the CAM system has required more than 4 hours. The additional requirement proposed by TVA is acceptable.

11. Section 4.6.F (p. 182) - TVA proposes to add a requirement under recirculation pump operation that "before starting either recirculation pump during steady state operation, check and log the loop discharge temperature and dome saturation temperature". The additional surveillance requirement is acceptable.

12. Table 3.7.A - Unit 2 only (p.251) - This table lists the primary containment isolation valves. During the last outages for each of the Browns Ferry units, a 1 in. bypass valve was added around the HPCI steam supply outboard isolation valve (FCV73-3) to relieve thermal stresses previously associated with the quarterly surveillance testing on the HPCI isolation valve. The 1 in. bypass valve serves as an isolation valve and needs to be added to Table 3.7.A. This was done as part of the most recent reload amendments for Units 1 and 3 (Amendment Nos. 76 and 51 dated September 15, 1981 and March 29, 1982, respectively). This amendment accomplishes the same change for Unit 2.

13. Tables 3.7.A and 3.7.D - Unit 2 only (pgs. 251A and 261A) - As noted above, these tables list primary containment isolation valves. During the most recent refueling outages, TVA replaced the hydrogen-oxygen containment monitoring systems in all three units. The sampling and return lines for these monitoring systems contain isolation valves that need to be added to the tables and periodically tested. The valves were added to the Technical Specifications for Units 1 and 3 as part of the last reload amendments (Amendment Nos. 76 and 51). This amendment adds the same valves to Tables 3.7.A and 3.7.D for Unit 2.

14. Table 3.7.A - Units 1 and 2 only (p. 252) - During the last refueling outage for each Unit, system suction isolation valves FCV 32-62 and 32-63 were added to the drywell air compressors. These compressors supply air to the air-operated valves in containment. The valves need to be added to Table 3.7.A. This was accomplished for Unit 3 in the last reload Amendment (Amendment No. 51 dated March 29, 1982). These Amendments add the valves to the Units 1 and 2 Technical Specifications.

15. Section 6.7.3.C (p. 356) - This section specifies whenever a "Special Report" is required to be submitted to the NRC. At our request, requirements are being added to the Technical Specifications to submit a special report a) if the seismic instrumentation is inoperable for more than a specified period of time, b) if both the thermocouple and acoustic monitor on a safety-relief valve tailpipe become inoperable or c) if the seismic instruments are actuated. The additional requirements were requested by the NRC staff and are acceptable.

16. Appendix B, Sections 3.3 and 5.5.3 - TVA proposes two minor, adminstrative changes to Appendix B of the Technical Specifications. At the end of Section 3.3 (p. 11), the licensee proposes to add a reference to Section 6.7.3.D of the Appendix A Technical Specifications. In Section 5.5.3, the proposed revision is to require that changes in monitoring program procedures be approved by PORC (Plant Operations Review Committee) as well as by plant management. The proposed changes are acceptable.

3.0 Environmental Consideration

We have determined that these amendments do not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Having made this determination, we have further concluded that these amendments involve an action which is insignificant from the standpoint of environmental impact, and pursuant to 10 CFR Section 51.5(d)(4) that an environmental impact statement, or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of these amendments.

4.0 Conclusion

We have concluded, based on the considerations discussed above, that: (1) because the amendments do not involve a significant increase in the probability or consequences of an accident previously evaluated, do not create the possibility of an accident of a type different from any evaluated previously, and do not involve a significant reduction in a margin of safety, the amendments do not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Dated: July 22, 1982

UNITED STATES NUCLEAR REGULATORY COMMISSION

DOCKET NOS. 50-259, 50-260, AND 50-296

TENNESSEE VALLEY AUTHORITY

NOTICE OF ISSUANCE OF AMENDMENTS TO FACILITY

OPERATING LICENSES

The U. S. Nuclear Regulatory Commission (the Commission) has issued Amendment No. 85 to Facility Operating License No. DPR-33, Amendment No. 82 to Facility Operating License No. DPR-52, and Amendment No. 56 to Facility Operating License No. DPR-68 issued to Tennessee Valley Authority (the licensee), which revised Technical Specifications for operation of the Browns Ferry Nuclear Plant, Units Nos. 1, 2, and 3, located in Limestone County, Alabama. The amendments are effective as of the date of issuance.

These revisions to the Technical Specifications consist of clarification and administrative changes, additions to reflect plant modifications and reorganization of some sections.

The application for the amendments complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendments. Prior public notice of these amendments was not required since the amendments do not involve a significant hazards consideration.

The Commission has determined that the issuance of these amendments will not result in any significant environmental impact and that pursuant to 10 CFR §51.5(d)(4) an environmental impact statement or negative declaration

and environmental impact appraisal need not be prepared in connection with issuance of these amendments.

For further details with respect to this action, see (1) the application for amendments dated May 15, 1981, as supplemented by letters dated June 16, 1981 and September 28, 1981, (2) Amendment No. 85 to License No. DPR-33, Amendment No. 82 to License No. DPR-52, and Amendment No. 56 to License No. DPR-68, and (3) the Commission's related Safety Evaluation. All of these items are available for public inspection at the Commission's Public Document Room, 1717 H Street, N.W., Washington, D. C. and at the Athens Public Library, South and Forrest, Athens, Alabama 35611. A copy of items (2) and (3) may be obtained upon request addressed to the U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, Attention: Director, Division of Licensing.

Dated at Bethesda, Maryland, this 22nd day of July 1982.

FOR THE NUCLEAR REGULATORY COMMISSION

Domenic B. Vassallo, Chief
Operating Reactors Branch #2
Division of Licensing