TENNESSEE VALLEY AUTHORITY

CHATTANOOGA, TENNESSEE 37401

400 Chestnut Street Tower II

August 6, 1979

TVA BFNP TS 127

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Denton:

In the Matter of the) Docket No. 50-296
Tennessee Valley Authority)

In accordance with the provisions of 10 CFR Part 50.59, we are enclosing 40 copies of a requested amendment to license DPR-68 to change the technical specifications of Browns Ferry Nuclear Plant unit 3 (Enclosure 1). The proposed amendment requests changes in the technical specifications to accommodate reload 2 cycle 3 operation of unit 3 and as a result of eliminating the LPCI loop selection logic approved by Amendment 23 to license DPR-68. Also enclosed are 40 copies of the justification for the proposed changes as addressed in NEDO-24199 (Enclosure 2). The LOCA analysis as referenced in NEDO-24199 will be submitted to you in the near future under separate cover.

TVA now plans to shut down unit 3 on August 26, 1979, to begin the refueling outage and to restart on November 24, 1979. In order to avoid impacting the scheduled startup we need your approval of this proposed change by November 9, 1979.

In accordance with the requirements of 10 CFR Part 170.22, we have determined the proposed amendment to be Class III. This classification is based on the fact that the proposed amendment involves a single safety issue which does not involve a significant hazard consideration. The remittance of $4000 is being wired to the NRC, Attention: Licensing Fee Management Branch.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills

L. M. Mills, Manager
Nuclear Regulation and Safety

Subscribed and sworn to before
me this 6 day of August 1979.

Lisa Bradbury
Notary Public
My Commission Expires Oct. 4, 1981

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7908080 519 P

Enclosures
cc: See page 2

Mr. Harold R. Denton August 6, 1979

cc (Enclosures):
Mr. Charles R. Christopher
Chairman, Limestone County Commission
P.O. Box 188
Athens, Alabama 35611

Dr. Ira L. Myers
State Health Officer
State Department of Public Health
State Office Building
Montgomery, Alabama 36104

ENCLOSURE 1

GUIDE TO PROPOSED CHANGES TO
BROWNS FERRY UNIT 3 TECHNICAL SPECIFICATIONS

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1.1 FUEL CLADDING INTEGRITY

2.1 FUEL CLADDING INTEGRITY

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 the prescribed limits.

Surveillance requirements for APRM scram set-points are given in Specification 4.1.B).

2. 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.

3. IRM--The IRM scram shall be set at less than or equal to 120/125 of full scale.

1.1 FUEL CLADDING INTEGRITY

C. Whenever the reactor is in the shutdown condition with 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

C.	Scram and isolation reactor low water level	≥ 538 in. above vessel zero
D.	Scram--turbine stop valve closure	≤ 10 percent valve closure
E.	Scram--turbine control valve	
	1. Fast closure--Upon trip of the fast acting solenoid valves	
	2. Loss of control oil pressure	≥ 1,100 psig
F.	Scram--low condenser vacuum	≥ 23 inches Hg vacuum
G.	Scram--main steam line isolation	≤ 10 percent valve closure
H.	Main steam isolation valve closure --nuclear system low pressure	≤ 850 psig
I.	Core spray and LPCI actuation--reactor low water level	≥ 378 in. above vessel zero
J.	HPCI and RCIC actuation--reactor low water level	≥ 470 in. above vessel zero
K.	Main steam isolation valve closure--reactor low water level	≥ 470 in. above vessel zero

should drop below the top of the fuel during this time, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation. As long as the fuel remains covered with water, sufficient cooling is available to prevent fuel clad perforation.

The safety limit has been established at 17.7 in. above the top of the irradiated fuel to provide a point which can be monitored and also provide adequate margin. This point corresponds approximately to the top of the actual fuel assemblies and also to the lower reactor low water level trip (378" above vessel zero).

REFERENCE

1. General Electric BWR Thermal Analysis Basis (GETAB) Data, Correlation and Design Application, NEDO 10958, and NEDE 10958.

2. General Electric Supplemental Reload Licensing Submittal for BFNP unit 3 Reload 2, NEDO-24199.

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 scrams set at 10 percent of valve closure, neutron flux does not increase.

I. J. & K. <u>Reactor low water level set point for initiation of HPCI and RCIC, closing main steam isolation valves, and starting LPCI and core spray pumps</u>

These systems maintain adequate coolant inventory and provide core cooling with the objective of preventing excessive clad temperatures. The design of these systems to adequately perform the intended function is based on the specified low level scram set point and initiation set points. Transient analyses reported in Section N14 of the FSAR demonstrate that these conditions result in adequate safety margins for both the fuel and the system pressure.

L. <u>References</u>

1. Linford, R. B., "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," NEDO-10802, Feb., 1973.

2. General Electric Supplemental Reload Licensing Submittal for BFNP Unit 3 Reload 2, NEDO-24199.

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The safety limit of 1,375 psig actually applies to any point in the reactor vessel; however, because of the static water head, the highest pressure point will occur at the bottom of the vessel. Because the pressure is not monitored at this point, it cannot be directly determined if this safety limit has been violated. Also, because of the potentially varying head level and flow pressure drops, an equivalent pressure cannot be a priori determined for a pressure monitor higher in the vessel. Therefore, following any transient that is severe enough to cause concern that this safety limit was violated, a calculation will be performed using all available information to determine if the safety limit was violated.

REFERENCES

1. Plant Safety Analysis (BFNP FSAR Section N14.0)
2. ASME Boiler and Pressure Vessel Code Section III
3. USAS Piping Code, Section B31.1
4. Reactor VEssel and Appurtenances Mechanical Design (BFNP FSAR Subsection 4.2)
5. General Electric Supplemental Reload Licensing Submittal for BFNP Unit 3 Reload 2, NEDO-24199.

2.2 BASES

REACTOR COOLANT SYSTEM INTEGRITY

The pressure relief system for each unit at the Browns Ferry Nuclear Plant has been sized to meet two design bases. First, the total safety/relief valve capacity has been established to meet the overpressure protection criteria of the ASME Code. Second, the distribution of this required capacity between safety valves and relief valves has been set to meet design basis 4.4.4-1 of subsection 4.4 which states that the nuclear system relief valves shall prevent opening of the safety valves during normal plant isolations and load rejections.

The details of the analysis which shows compliance with the ASME Code requirements is presented in subsection 4.4 of the FSAR and the Reactor Vessel Overpressure Protection Summary Technical Report submitted in response to question 4.1 dated December 1, 1971.

To meet the safety design basis, thirteen safety-relief valves have been installed on each unit with a total capacity of 84.2% of nuclear boiler rated steam flow. The analysis of the worst overpressure transient, (3-second closure of all main steam line isolation valves) neglecting the direct scram (valve position scram) results in a maximum vessel pressure of 1280 psig if a neutron flux scram is assumed. This results in a 95 psig margin to the code allowable overpressure limit of 1375 psig.

To meet the operational design basis, the total safety-relief capacity of 84.2% of nuclear boiler rated has been divided into 70% relief (11 valves) and 14.2% safety (2 valves). The analysis of the plant isolation transient (turbine trip with bypass valve failure to open) assuming a turbine trip scram is presented in Reference 5 on page 29. This analysis shows that the 11 relief valves limit pressure at the safety valves to 1206 psig, well below the setting of the safety valves. Therefore, the safety valves will not open. This analysis shows that peak system pressure is limited to 1232 psig which is 143 psig below the allowed vessel overpressure of 1375 psig.

Table 3.2.B
INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
2	Instrument Channel - Reactor Low Water Level	≥ 470" above vessel zero.	A	1. Below trip setting initiated HPCI.
2	Instrument Channel - Reactor Low Water Level	≥ 470" above vessel zero.	A	1. Multiplier relays initiate RCIC.
2	Instrument Channel - Reactor Low Water Level (LIS-3-58A-D, SW #1)	≥ 378" above vessel zero.	A	1. Below trip setting initiates CSS. Multiplier relays initiate LPCI. 2. Multiplier relay from CSS initiates accident signal (15).
2(16)	Instrument Channel - Reactor Low Water Level (LIS-3-58A-D, SW #2)	≥ 378" above vessel zero.	A	1. Below trip settings in conjunction with drywell high pressure, low water level permissive, 120 sec. del timer and CSS or RHR pump running, initiates ADS.
1(16)	Instrument Channel - Reactor Low Water Level Permissive (LIS-3-184 & 185, SW #1)	≥ 544" above vessel zero.	A	1. Below trip setting permissive for initiating signals on ADS.
1	Instrument Channel - Reactor Low Water Level (LITS-3-52 & 62, SW #1)	≥ 312 5/16" above vessel zero. (2/3 core height)	A	1. Below trip setting prevents inadvertent operation of of containment spray during accident condition.

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Table 3.2.B
INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
2	Instrument Channel - Reactor Low Pressure (PS-3-74 A & B, SW #2) (PS-68-95, SW #2) (PS-68-96, SW #2)	450 psig ± 15	A	1. Below trip setting permissive for opening CSS and LPCI admission valves.
2	Instrument Channel - Reactor Low Pressure (PS-3-74A & B, SW #1) (PS-68-95, SW #1) (PS-68-96, SW #1)	230 psig ± 15	A	1. Recirculation discharge valve actuation.
1	Instrument Channel - Reactor Low Pressure (PS-68-93 & 94, SW #1)	100 psig ± 15	A	1. Below trip setting in conjunction with containment isolation signal and both suction valves open will close RHR (LPCI) admission valves.
2	Core Spray Auto Sequencing Timers (5)	$6 \leq t \leq 8$ secs.	B	1. With diesel power . One per motor
2	LPCI Auto Sequencing Timers (5)	$0 \leq t \leq 1$ sec.	B	1. With diesel power 2. One per motor
1	RHRSW A1, B3, C1, and D3 Timers	$13 \leq t \leq 15$ sec.	A	1. With diesel power 2. One per pump

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Table 3.2.B
INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
2	Core Spray and LPCI Auto Sequencing Timers (6)	$0 \leq t \leq 1$ sec. $6 \leq t \leq 8$ sec. $12 \leq t \leq 16$ sec. $18 \leq t \leq 24$ sec.	B	1. With normal power 2. One per CSS motor 3. Two per RHR motor
1	RHRSW A1, B3, C1, and D3 Timers	$27 \leq t \leq 29$ sec.	A	1. With normal power 2. One per pump
1(16)	ADS Timer	120 sec $\pm$ 5	A	1. Above trip setting in conjunction with low reactor water level, high drywell pressure and LPCI or CSS pumps running initiates ADS.
2	Instrument Channel - RHR Discharge Pressure	100 $\pm$ 10 psig	A	1. Below trip setting defers ADS actuation.

Table 3.2.B
INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
2	Instrument Channel CSS Pump Discharge Pressure	185 ± 10 psig	A	1. Below trip setting defers ADS actuation.
1(3)	Core Spray Sparger to Reactor Pressure Vessel d/p	2 psid ± 0.4	A	1. Alarm to detect core spray sparger pipe break.
1	RHR (LPCI) Trip System bus power monitor	N/A	C	1. Monitors availability of power to logic systems.

Table 3.2.B

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
2(2)	Instrument Channel - Reactor High Water Level	≤583" above vessel zero.	A	1. Above trip setting trips HPCI turbine.
1	Instrument Channel - HPCI Turbine Steam Line High Flow	≤ 90 psi (7)	A	1. Above trip setting isolates HPCI system and trips HPCI turbine.
4(4)	Instrument Channel - HPCI Steam Line Space High Temperature	≤200°F.	A	1. Above trip setting isolates HPCI system and trips HPCI turbine.
1	Core Spray System Logic	N/A	B	1. Includes testing auto initiation inhibit to Core Spray Systems in other units.
1	RCIC System (Initiating) Logic	N/A	B	1. Includes Group 7 valves. Refer to Table 3.7.A for list of valves.
1	RCIC System (Isolation) Logic	N/A	B	1. Includes Group 5 valves. Refer to Table 3.7.A for list of valves.
1(16)	ADS Logic	N/A	A	
1	RHR (LPCI) System (Initiation)	N/A	B	

10. Only one trip system for each cooler fan.

11. In only two of the four 4160 V shutdown boards. See note 13.

12. In only one of the four 4160 V shutdown boards. See note 13.

13. An emergency 4160 V shutdown board is considered a trip system.

14. RHRSW pump would be inoperable. Refer to section 4.5.C for the requirements of a RHRSW pump being inoperable.

15. The accident signal is the satisfactory completion of a one-out-of-two taken twice logic of the drywell high pressure plus low reactor pressure or the vessel low water level (≥ 378" above vessel zero) originating in the core spray system trip system.

16. The ADS circuitry is capable of accomplishing its protective action with one operable trip system. Therefore one trip system may be taken out of service for functional testing and calibration for a period not to exceed 8 hours.

[illegible]. Two RPT systems exist, either of which will trip both recirculation pumps. The systems will be individually functionally tested monthly. If the test period for one RPT system exceeds 2 consecutive hours, the system will be declared inoperable. If both RPT systems are inoperable or if 1 RPT system is inoperable for more than 72 consecutive hours, an orderly power reduction shall be initiated and the reactor power shall be less than 85% within 4 hours.

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TABLE 4.2.B
SURVEILLANCE REQUIREMENTS FOR INSTRUMENTATION THAT INITIATE OR CONTROL THE CSCS

Function	Functional Test	Calibration	Instrument Check
Instrument Channel Reactor Low Pressure (PS-3-74A & B) (PS-68-95) (PS-68-96)	(1)	once/3 months	none
Instrument Channel Reactor Low Pressure (PS-68-93 & 94)	(1)	once/3 months	none
Core Spray Auto Sequencing Timers (Normal Power)	(4)	once/operating cycle	none
Core Spray Auto Sequencing Timers (Diesel Power)	(4)	once/operating cycle	none
LPCI Auto Sequencing Timers (Normal Power)	(4)	once/operating cycle	none
LPCI Auto Sequencing Timers (Diesel Power)	(4)	once/operating cycle	none
RHRSW A1, B3, C1, D3 Timers (Normal Power)	(4)	once/operating cycle	none
RHRSW A1, B3, C1, D3 Timers (Diesel Power)	(4)	once/operating cycle	none

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TABLE 4.2.B
SURVEILLANCE REQUIREMENTS FOR INSTRUMENTATION THAT INITIATE OR CONTROL THE CSCS

Function	Functional Test	Calibration	Instrument Check
ADS Timer	(4)	once/operating cycle	none
Instrument Channel RHR Pump Discharge Pressure	(1)	once/3 months	none
Instrument Channel Core Spray Pump Discharge Pressure	(1)	once/3 months	none
Core Spray Sparger to RPV d/p	(1)	once/3 months	once/day
Trip System Bus Power Monitor	once/operating cycle	N/A	none
Instrument Channel Condensate Storage Tank Low Level	(1)	once/3 months	none

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TABLE 4.2.B
SURVEILLANCE REQUIREMENTS FOR INSTRUMENTATION THAT INITIATE OR CONTROL THE CSCS

Function	Functional Test	Calibration	Instrument Check
LPCI (Containment Spray) Logic	once/6 months	(6)	N/A
Core Spray Loop A Discharge Pressure (PI-75-20)	N/A	once/6 months	once/day
Core Spray Loop B Discharge Pressure (PI-75-48)	N/A	once/6 months	once/day
RHR Loop A Discharge Pressure (PI-74-51)	N/A	once/6 months	once/day
RHR Loop B Discharge Pressure (PI-74-65)	N/A	once/6 months	once/day
Instrument Channel - RHR Start	Tested during functional test of RHR pump (refer to section 4.5.B).	N/A	N/A
Instrument Channel - Thermostat (RHR Area Cooler Fan)	once/month	once/6 months	N/A
Instrument Channel - Core Spray A or C Start	Tested during functional test of core spray (refer to section 4.5.A).	N/A	N/A
Instrument Channel - Core Spray B or D start	Tested during functional test of core spray (refer	N/A	N/A

TABLE 4.2.B
SURVEILLANCE REQUIREMENTS FOR INSTRUMENTATION THAT INITIATE OR CONTROL THE CSCS

Function	Functional Test	Calibration	Instrument Check
	to section 4.5.A).		
Instrument Channel - Thermostat (Core Spray Area Cooler Fan)	once/ month	once/6 months	N/A
RHR Area Cooler Fan Logic	Tested during functional test of instrument channels, RHR motor start and thermostat (RHR area cooler fan). No other test required.	N/A	N/A
Core Spray Area Cooler Fan Logic	Tested during logic system functional test of instrument channels, core spray motor start and thermo-stat (core spray area cooler fan). No other test required.	N/A	N/A
Instrument Channel - Core Spray Motors A or D Start	Tested during functional test of core spray pump (refer to section 4.5.A).	N/A	N/A
Instrument Channel - Core Spray Motors B or C Start	Tested during functional test of core spray pump (refer to section 4.5.A).	N/A	N/A
RPT initiate logic	once/month	N/A	N/A
RPT breaker	once/operating cycle	N/A	N/A

and HPCI, and trips the recirculation pumps. The low reactor water level instrumentation that is set to trip when reactor water level is 17.7" (378" above vessel zero) above the top of the active fuel (Table 3.2.B) initiates the LPCI, Core Spray Pumps, contributes to ADS initiation and starts the diesel generators. These trip setting levels were chosen to be high enough to prevent spurious actuation but low enough to initiate CSCS operation so that post accident cooling can be accomplished and the guidelines of 10 CFR 100 will not be violated. For large breaks up to the complete circumferential break of a 28-inch recirculation line and with the trip setting given above, CSCS initiation is initiated in time to meet the above criteria.

The high drywell pressure instrumentation is a diverse signal to the water level instrumentation and in addition to initiating CSCS, it causes isolation of Groups 2 and 8 isolation valves. For the breaks discussed above, this instrumentation will initiate CSCS operation at about the same time as the low water level instrumentation; thus the results given above are applicalbe here also.

Venturis are provided in the main steam lines as a means of measuring steam flow and also limiting the loss of mass inventory from the vessel during a steam line break accident. The primary function of the instrumentation is to detect a break in the main steam line. For the worst case accident, main steam line break outside the drywell, a trip setting of 140% of rated steam flow in conjunction with the flow limiters and main steam line valve closure, limits the mass inventory loss such that fuel is not uncovered, fuel cladding temperatures remain below 1000°F and release of radioactivity to the environs is well below 10 CFR 100 guidelines. Reference Section 14.6.5 FSAR.

Temperature monitoring instrumentation is provided in the main steam line tunnel to detect leaks in these areas. Trips are provided on this instrumentation and when exceeded, cause closure of isolation valves. The setting of 200°F for the main steam line tunnel detector is low enough to detect leaks of the order of 15 gpm; thus, it is capable of covering the entire spectrum of breaks. For large breaks, the high steam flow instrumentation is a backup to the temperature instrumentation.

High radiation monitors in the main steam line tunnel have been provided to detect gross fuel failure as in the control rod drop accident. With the established setting of 3 times normal background, and main steam line isolation valve closure, fission product release is limited so that 10 CFR 100 guidelines are not exceeded for this accident. Reference Section 14.6.2 FSAR. An alarm, with a nominal set point of 1.5 x normal full power background, is provided also.

In the analytical treatment of the transients, 390 milliseconds are allowed between a neutron sensor reaching the scram point and the start of negative reactivity insertion. This is adequate and conservative when compared to the typically observed time delay of about 270 milliseconds. Approximately 70 milliseconds after neutron flux reaches the trip point, the pilot scram valve solenoid power supply voltage goes to zero an approximately 200 milliseconds later, control rod motion begins. The 200 milliseconds are included in the allowable scram insertion times specified in Specification 3.3.C.

In order to perform scram time testing as required by specification 4.3.C.1, the relaxation of certain restraints in the rod sequence control system is required. Individual rod bypass switches may be used as described in specification 4.3.C.1.

The position of any rod bypassed must be known to be in accordance with rod withdrawal sequence. Bypassing of rods in the manner described in specification 4.3.C.1 will allow the subsequent withdrawal of any rod scrammed in the 100 percent to 50 percent rod density groups; however, it will maintain group notch control over all rods in the 50 percent to 0 percent rod density groups. In addition, RSCS will prevent movement of rods in the 50 percent density to a preset power level range until the scrammed rod has been withdrawn.

D. Reactivity Anomalies

During each fuel cycle excess operative reactivity varies as fuel depletes and as any burnable poison in supplementary control is burned. The magnitude of this excess reactivity may be inferred from the critical rod configuration. As fuel burnup progresses, anomalous behavior in the excess reactivity may be detected by comparison of the critical rod pattern at selected base states to the predicted rod inventory at that state. Power operating base conditions provide the most sensitive and directly interpretable data relative to core reactivity. Furthermore, using power operating base conditions permits frequent reactivity comparisons.

Requiring a reactivity comparison at the specified frequency assures that a comparison will be made before the core reactivity change exceeds 1% ΔK. Deviations in core reactivity greater than 1% ΔK are not expected and require thorough evaluation. One percent reactivity limit is considered safe since an insertion of the reactivity into the core would not lead to transients exceeding design conditions of the reactor system.

References

1. General Electric Supplemental Reload Licensing Submittal for BFNP unit 3 Reload 2, NEDO-24159, July 1979.

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3.5 CORE AND CONTAINMENT COOLING SYSTEMS

B. Residual Heat Removal System (RHRS) (LPCI and Containment Cooling)

1. The RHRS shall be operable:

(1) prior to a reactor startup from a Cold Condition; or

(2) when there is irradiated fuel in the reactor vessel and when the reactor vessel pressure is greater than atmospheric, except as specified in specifications 3.5.B.2, through 3.5.B.7 and 3.9.B.3.

2. With the reactor vessel pressure less than 105 psig, the RHR may be removed from service (except that two RHR pumps-containment cooling mode and associated heat exchangers must remain operable) for a period not to exceed 24 hours while being drained of

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

B. Residual Heat Removal System (RHRS) (LPCI and Containment Cooling)

1.

a.	Simulated Automatic Actuation Test	Once/ Operating Cycle
b.	Pump Operability	Once/ month
c.	Motor Operated valve operability	Once/ month
d.	Pump Flow Rate	Once/3 Months
e.	Testable check valve	Once/ operating cycle

Each LPCI pump shall deliver 9,000 gpm against an indicated system pressure of 125 psig. Two LPCI pumps in the same loop shall deliver 15,000 gpm against an indicated system pressure of 200 psig.

2. An air test on the drywell and torus headers and nozzles shall be conducted once/5 years. A water test may be performed on the torus header in lieu of the air test.

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3.5 CORE AND CONTAINMENT COOLING SYSTEMS

suppression chamber quality water and filled with primary coolant quality water provided that during cooldown two loops with one pump per loop or one loop with two pumps, and associated diesel generators, in the core spray system are operable.

3. If one RHR pump (LPCI mode) is inoperable, the reactor may remain in operation for a period not to exceed seven days provided the remaining RHR pumps (LPCI mode) and both access paths of the RHRS (LPCI mode) and the CSS and the diesel generators remain operable.

4. If any 2 RHR pumps (LPCI mode) become inoperable, the reactor shall be placed in the cold shutdown condition within 24 hours.

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3. When it is determined that one RHR pump (LPCI mode) is inoperable at a time when operability is required, the remaining RHR pumps (LPCI mode) and active components in both access paths of the RHRS (LPCI mode) and the CSS and the diesel generators shall be demonstrated to be operable immediately and daily thereafter.

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5. If one RHR pump (containment cooling Mode) or associated heat exchanger is inoperable, the reactor may remain in operation for a period not to exceed 30 days provided the remaining RHR pumps (containment cooling mode) and associated heat exchangers and diesel generators and all access paths of the RHRS (containment cooling mode) are operable.

6. If two RHR pumps (containment cooling mode) or associated heat exchangers are inoperable, the reactor may remain in operation for a period not to exceed 7 days provided the remaining RHR pumps (containment cooling mode) and associated heat exchangers and all access paths of the RHRS (containment cooling mode) are operable.

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4. No additional surveillance required.

5. When it is determined that one RHR pump (containment cooling mode) or associated heat exchanger is inoperable at a time when operability is required, the remaining RHR pumps (containment cooling mode), the associated heat exchangers and diesel generators, and all active components in the access paths of the RHRS (containment cooling mode) shall be demonstrated to be operable immediately and weekly thereafter until the inoperable RHR pump (containment cooling Mode) and associated heat

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3.5 CORE AND CONTAINMENT COOLING SYSTEMS

(Note: Because cross-connect capability is not a short term requirement, a component is not considered inoperable if cross-connect capability can be restored to service within 5 hours.)

12. If one RHR pump or associated heat exchanger located on the unit cross-connection in unit 2 is inoperable for any reason (including valve inoperability, pipe break, etc.), the reactor may remain in operation for a period not to exceed 30 days provided the remaining RHR pump and associated diesel generator are operable.

13. If RHR cross-connection flow or heat removal capability is lost, the unit may remain in operation for a period not to exceed 10 days unless such capability is restored.

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adjacent unit is inoperable at a time when operability is required, the remaining RHR pump and associated heat exchanger on the unit cross-connection and the associated diesel generator shall be demonstrated to be operable immediately and every 15 days thereafter until the inoperable pump and associated heat exchanger are returned to normal service.

12. No additional surveillance required.

13. No additional surveillance required.

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3.5 CORE AND CONTAINMENT COOLING SYSTEMS

and corresponding action shall contiaue until reactor operation is within the prescribed limits.

K. Minimum Critical Power Ratio (MCPR)

The MCPR operating limit is 1.28 for 8x8 fuel, and 1.22 for 8x8R fuel, and 1.23 for P8x8R fuel. These limits apply to steady state power operation at rated power and flow. For core flows other than rated, the MCPR shall be greater than the above limits times K_f. K_f is the value shown in Figure 3.5.2. If at any time during operation, it is determined by normal surveillance that the limiting value for MCPR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the steady state MCPR is not returned to within the prescribed limits within two (2) hours, the reactor shall be brought to the Cold Shutdown condition within 36 hours. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

L. Reporting Requirements

If any of the limiting values identified in Specifications 3.5.I, J, or K are exceeded and the specified remedial action is taken, the event shall be logged and reported in a 30-day written report.

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

K. Minimum Critical Power Ratio (MCPR)

MCPR shall be determined daily during reactor power operation at ≥ 25% rated thermal power and following any change in power level or distribution that would cause operation with a limiting control rod pattern as described in the bases for Specification 3.3.

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adequate core cooling. With due regard for this margin, the allowable repair time of 7 days was chosen.

Should one RHR pump (LPCI mode) become inoperable, only 3 RHR pumps (LPCI mode) and the core spray system are available. Since this leaves only one RHR pump (LPCI mode) in reserve, which along with the remaining 2 RHR pumps (LPCI mode) and core spray system is demonstrated to be operable immediately and daily thereafter, a 7 day repair period is justified.

Should two RHR pumps (LPCI mode) become inoperable, there remains no reserve (redundant) capacity within the RHRS (LPCI mode). Therefore, the affected unit shall be placed in cold shutdown within 24 hours.

Should one RHR pump (containment cooling mode) become inoperable, a complement of three full capacity containment heat removal systems is still available. Any two of the remaining pumps/heat exchanger combinations would provide more than adequate containment cooling for any abnormal or post accident situation. Because of the availability of equipment in access of normal redundance requirements, which is demonstrated to be operable immediately and with specified subsequent performance, a 30-day repair period is justified.

Should two RHR pumps (containment cooling mode) become inoperable, a full heat removal system is still available. The remaining pump/heat exchanger combinations would provide adequate containment cooling for any abnormal post accident situation. Because of the availability of a full complement of heat removal equipment, which is demonstrated to be operable immediately and with specified performance, a 7-day repair period is justified.

Observation of the stated requirements for the containment cooling mode assures that the suppression pool and the drywell will be sufficiently cooled, following a loss-of-coolant accident, to prevent primary containment overpressurization. The containment cooling function of the RHRS is permitted only after the core has reflooded to the two-thirds core height level. This prevents inadvertently diverting water needed for core flooding to the less urgent task of containment cooling. The two-thirds core height level interlock may be manually bypassed by a keylock switch.

Since the RHRS is filled with low quality water during power operation, it is planned that the system be filled with demineralized (condensate) water before using the shutdown cooling function of the RHR system. Since it is desirable to

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testing to ensure that the lines are filled. The visual checking will avoid starting the core spray or RHR system with a discharge line not filled. In addition to the visual observation and to ensure a filled discharge line other than prior to testing, a pressure suppression chamber head tank is located approximately 20 feet above the discharge line highpoint to supply makeup water for these systems. The condensate head tank located approximately 100 feet above the discharge high point serves as a backup charging system when the pressure suppression chamber head tank is not in service. System discharge pressure indicators are used to determine the water level above the discharge line high point. The indicators will reflect approximately 30 psig for a water level at the high point and 45 psig for a water level in the pressure suppression chamber head tank and are monitored daily to ensure that the discharge lines are filled.

When in their normal standby condition, the suction for the HPCI and RCIC pumps are aligned to the condensate storage tank, which is physically at a higher elevation than the HPCIS and RCICS piping. This assures that the HPCI and RCIC discharge piping remains filled. Further assurance is provided by observing water flow from these systems high points monthly.

I. Maximum Average Planar Linear Heat Generation Rate (MAPLHGR)

This specification assures that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the limit specified in the 10 CFR 50, Appendix K.

The peak cladding temperature following a postulated loss-of-coolant accident is primarily a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is only dependent secondarily on the rod to rod power distribution within an assembly. Since expected local variations in power distribution within a fuel assembly affect the calculated peak clad temperature by less than $\pm$ 20°F relative to the peak temperature for a typical fuel design, the limit on the average linear heat generation rate is sufficient to assure that calculated temperatures are within the 10 CFR 50 Appendix K limit. The limiting value for MAPLHGR is shown in Tables 3.5.I-1, -2, -3. The analyses supporting these limiting values is presented in NEDO-24127 and NEDO-24194.

J. Linear Heat Generation Rate (LHGR)

This specification assures that the linear heat generation rate in any rod is less than the design linear heat

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computed and reported quarterly. It must be recognized that there is always an action which would return any of the parameters (MAPLHGR, LHGR, or MCPR) to within prescribed limits, namely power reduction. Under most circumtances, this will not be the only alternative.

M. References

1. "Fuel Densification Effects on General Electric Boiling Water Reactor Fuel," Supplements 6, 7, and 8, NEDM-10735, August 1973.

2. Supplement 1 to Technical Report on Densifications of General Electric Reactor Fuels, December 14, 1974 (USA Regulatory Staff).

3. Communication: V. A. Moore to I. S. Mitchell, "Modified GE Model for Fuel Densification," Docket 50-321, March 27, 1974.

4. General Electric Supplemental Reload Licensing Submittal for BFNP Unit 3 Reload 2, NEDO-24199.

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TABLE 3.5.I-1

MAPLHGR VERSUS AVERAGE PLANAR EXPOSURE

Plant: BF-3 Fuel Type: Inital Core - Type 2

Average Planar Exposure (Mwd/t)	MAPLHGR (kW/ft)
200	11.4
1,000	11.6
5,000	12.0
10,000	12.2
15,000	12.3
20,000	12.1
25,000	11.3
30,000	10.2

TABLE 3.5.I-2

MAPLHGR VERSUS AVERAGE PLANAR EXPOSURE

Plant: BF-3 Fuel Type: Initial Core - Type 1

Average Planar Exposure (Mwd/t)	MAPLHGR (kW/ft)
200	11.2
1,000	11.3
5,000	11.8
10,000	12.1
15,000	12.3
20,000	12.1
25,000	11.3
30,000	10.2

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TABLE 3.5.I-3

MAPLHGR VERSUS AVERAGE PLANAR EXPOSURE

Plant: BF-3

FUEL TYPES: 8DRB265L
and
P8DRB265L

Average Planar Exposure (Mwd/t)	MAPLHGR (kW/ft)
200	11.6
1,000	11.6
5,000	12.1
10,000	12.1
15,000	12.1
20,000	11.9
25,000	11.3
30,000	10.7

The values in this table are conservative for both prepressurized and non-pressurized fuel.

3.6 PRIMARY SYSTEM BOUNDARY

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.

4.6 PRIMARY SYSTEM BOUNDARY

F. Jet Pump Flow Mismatch

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

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3.6 PRIMARY SYSTEM BOUNDARY

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 maintained at the level required by the original acceptance standards throughout the life of the plant. The reactor shall be maintained in a cold shutdown condition until each indication of a defect has been investigated and evaluated.

4.6 PRIMARY SYSTEM BOUNDARY

G. Structural Integrity

1. Table 4.6.A together with supplementary notes, specifies the inservice inspection surveillance requirements of the reactor coolant system as follows:

   a. areas to be inspected

   b. percent of areas to be inspected during the inspection interval

   c. inspection frequency

   d. methods used for inspection

2. Evaluation of inservice inspections will be made to the acceptance standards specified for the original equipment.

3. The inspection interval shall be 10 years.

4. Additional inspections shall be performed on certain circumferential pipe welds as listed to provide additional protection against pipe whip, which could damage auxiliary and control systems.

   Feedwater- GFW-9, KFW-13, GFW-12, GFW-26, KFW-31, GFW-29, KFW-39, GFW-15, KFW-38, and GFW-32

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3.6/4.6 BASES

To meet the safety design basis, thirteen safety-relief valves have been installed on unit 2 with a total capacity of 84.2% of nuclear boiler rated steam flow. The analysis of the worst overpressure transient, (3-second closure of all main steam line isolation valves) neglecting the direct scram (valve position scram) results in a maximum vessel pressure of 1280 psig if a neutron flux scram is assumed
This results in an 95 psig margin of the code allowable overpressure limit of 1375 psig.
To meet the operational design basis, the total safety-relief capacity of 84.2% of nuclear bo'ler rated has been divided into 70% relief (11 valves) and 14.2% safety (2 valves). The analysis of the plant isolation transient (turbine trip with bypass valve failure to open) assuming a turbine trip scram is presented in Reference 5 on page 29. This analysis shows that the 11 relief valves limit pressure at the safety valves to 1206 psig, well below the setting of the safety valves. Therefore, the safety valves will not open. This analysis shows that peak system pressure is limited to 1232 psig which is 143 psig below the allowed vessel overpressure of 1375 psig.

Experience in relief and safety valve operation shows that a testing of 50 percent of the valves per year is adequate to detect failures or deteriorations. The relief and safety valves are benchtested every second operating cycle to ensure that their set points are within the ± 1 percent tolerance. The relief valves are tested in place once per operating cycle to establish that they will open and pass steam.

The requirements established above apply when the nuclear system can be pressurized above ambient conditions. These requirements are applicable at nuclear system pressures below normal operating pressures because abnormal operational transients could possibly start at these conditions such that eventual overpressure relief would be needed. However, these transients are much less severe, in terms of pressure, than those starting at rated conditions. The valves need not be functional when the vessel head is removed, since the nuclear system cannot be pressurized.

REFERENCES

1. Nuclear System Pressure Relief System (BFNP FSAR Subsection 4.4)

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3.6/4.6 BASES

A nozzle-riser system failure could also generate the coincident failure of a jet pump diffuser body; however, the converse is not true. The lack of any substantial stress in the jet pump diffuser body makes failure impossible without an initial nozzle-riser system failure.

3.6.F/4.6.F Jet Pump Flow Mismatch

Requiring the discharge valve of the lower speed loop to remain closed until the speed of the faster pump is below 50% of its rated speed provides assurance when going from one to two pump operation that excessive vibration of the jet pump risers will not occur.

ECCS performance during reactor operation with one recirculation loop out of service has not been analyzed. Therefore, sustained reactor operation under such conditions is not permitted.

3.6.G/4.6.G Structural Integrity

The requirements for the reactor coolant systems inservice inspection program have been identified by evaluating the need for a sampling examination of areas of high stress and highest probability of failure in the system and the need to meet as closely as possible the requirements of Section XI, of the ASME Boiler and Pressure Vessel Code.

The program reflects the built-in limitations of access to the reactor coolant systems.

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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 a e actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (470")
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 System High Temperature
3. Reactor Water Cleanup System High Drain Temperature

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

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

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: The valves in Group 7 are automatically actuated by

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only the following condition:

1. Reactor Vessel Low Water Level (470")

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

1. High Drywell Pressure

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 required to minimize the potential leakage paths from e containment in the event of a loss of coolant accident.

Group 1 - process lines are isolated by reactor vessel low water level (470") 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 are also closed when process instrumentation detects excessive main steam line flow, high radiation, low pressure, or main steam space high temperature.

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 non-safety 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 flow through the inlet to the cleanup system. Also, since the vessel could potentially be drained through the cleanup system, a low level isolation is provided.

Group 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 Group 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 - process lines are closed only on reactor low water level (470"). These close on the same signal that initiates HPCIS and RCICS to ensure that the valves are not open when HPCIS or RCICS action is required.

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

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3.9 AUXILIARY ELECTRICAL SYSTEM

2. Three unit 3 diesel generators shall be operable.

4.9 AUXILIARY ELECTRICAL SYSTEM

d. Each diesel generator shall be given an annual inspection in accordance 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 the acceptable limits specified in Table 1 of the latest revision to ASTM D975 and logged.

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

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3.9 AUXILIARY ELECTRICAL SYSTEM

5. The 250-Volt Shutdown Board battery and unit batteries and a battery charger for each battery and associated battery boards are operable.

6. Logic Systems

a. Accident signal logic system is operable.

7. There shall be a minimum of 103,300 gallons of diesel fuel in the unit 3 standby diesel generator fuel tanks.

4.9 AUXILIARY ELECTRICAL SYSTEM

c. The undervoltage relays which start the diesel generators from start buses 1A and 1B and the 4-kV shutdown boards, shall be calibrated annually for trip and reset and the measurements logged.

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3.9 AUXILIARY ELECTRICAL SYSTEM

4. From and after the date that the 250-Volt Shutdown board batteries or one of the three 250-Volt unit batteries and/or its associated battery board is found to be inoperable for any reason, continued reactor operation is permissible during the succeeding seven days. Except for routine surveillance testing, the NRC shall be notified within 24 hours of the situation, the precautions to be taken during this period and the plans to return the failed component to an operable state.

5. When one division of the Logic System is inoperable, continued reactor operation is permissible under this condition for seven days, provided the CSCS requirements listed in Specification 3.9.B.2 are satisfied. The NRC shall be notified within 24 hours of the situation, the precautions to be taken during this period and the plans to return the failed component to an operable state.

4.9 AUXILIARY ELECTRICAL SYSTEM

3.9 BASES

The objective of this specification is to assure an adequate source of electrical power to operate facilities to cool the unit during shutdown and to operate the engineered safeguards following an accident. There are three sources of alternating current electrical energy available, namely, the 161-kV transmission system, the nuclear generating units, and the diesel generators.

The 161-kV offsite power supply consists of two lines which are fed from different sections of the TVA 161-kV grid. In the normal mode of operation, the 161-kV system is operating and four diesel generators are operational. If one diesel generator is out of service, there normally remain the 161-kV sources, and the other three diesel generators. For a diesel generator to be considered operable its associated 125 V battery must be operable.

The minimum fuel oil requirement of 103,300 gallons is sufficient for 7 days of full load operation of 3 diesels and is conservatively based on availability of a replenishment supply.

Offsite auxiliary power for Browns Ferry Nuclear Plant Unit 3 is supplied from two sources: the unit station transformers from the main generator or the 161-kV transmission system through the cooling tower transformers. If a cooling tower transformer is lost, the unit can continue to operate since the station transformer is in service, the other cooling tower transformer is available, and four diesel generators are operational.

A 4-kV shutdown board is allowed to be out of operation for a brief period to allow for maintenance and testing, providing all remaining 4-kV shutdown boards and associated diesel generators CS, RHR, (LPCI and Containment Cooling) Systems supplied by the remaining 4-kV shutdown boards, and all emergency 480 V power boards are operable.

There are five 250-volt d-c battery systems each of which consists of a battery, battery charger, and distribution equipment. Three of these systems provide power for unit control functions, operative power for unit motor loads, and alternative drive power for a 115-volt a-c unit preferred motor-generator set. One 250-volt d-c system provides power for common plant and transmission system control functions, drive power for a 115-volt a-c plant preferred motor-generator set, and emergency drive power for certain unit large motor loads. The fifth battery system delivers control power to a 4-kV shutdown board.

The 250-Volt dc system is so arranged, and the batteries sized such, that the loss of any one unit battery will not prevent the safe shutdown and cooldown of all three units in the event of the loss of offsite power and a design basis accident in any one unit. Loss of control power to any engineered safeguard control

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5.0 MAJOR DESIGN FEATURES

5.1 SITE FEATURES

Browns Ferry units 1, 2, and 3 are located at Browns Ferry Nuclear Plant site on property owned by the United States and in custody of the TVA. The site shall consist of approximately 840 acres on the north shore of Wheeler Lake at Tennessee River Mile 294 in Limestone County, Alabama. The minimum distance from the outside of the secondary containment building to the boundary of the exclusion area as defined in 10 CFR 100.3 shall be 4,000 feet.

5.2 REACTOR

A. The reactor core may contain 764 fuel assemblies consisting of 8x8 assemblies having 63 fuel rods each, and 8x8 R (and P8x8R) assemblies having 62 fuel rods each. The number of each type in the core is given in the most recent reload amendment topical report.

B. The reactor core shall contain 185 cruciform-shaped control rods. The control material shall be boron carbide powder (B_4C) compacted to approximately 70 percent of theoretical density.

5.3 REACTOR VESSEL

The reactor vessel shall be as described in Table 4.2-2 of the FSAR. The applicable design codes shall be as described in Table 4.2-1 of the FSAR.

5.4 CONTAINMENT

A. The principal design parameters for the primary containment shall be given in Table 5.2-1 of the FSAR. The applicable design codes shall be as described in Section 5.2 of the FSAR.

B. The secondary containment shall be as described in Section 5.3 of the FSAR.

C. Penetrations to the primary containment and piping passing through such penetrations shall be designed in accordance with the standards set forth in Section 5.2.3.4 of the FSAR.

5.5 FUEL STORAGE

A. The arrangement of the fuel in the new-fuel storage facilitity shall be such that k_{eff}, for dry conditions,

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ENCLOSURE 2