APPENDIX A

TO

FACILITY OPERATING LICENSE DPR-33

TECHNICAL SPECIFICATION AND BASES

FOR

BROWNS FERRY NUCLEAR PLANT

UNIT 1

LIMESTONE COUNTY, ALABAMA

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-259

TABLE OF CONTENTS

Section		Page No.

Section		Page No.

Section		Page No.

LIST OF TABLES

LIST OF TABLES (Cont'd)

LIST OF ILLUSTRATIONS

BROWNS FERRY NUCLEAR PLANT UNIT 1
TECHNICAL SPECIFICATIONS

EFFECTIVE PAGE LISTING

PAGE	EFFECTIVE REVISION DATE
Appendix A	
i-viii	8-20-76
ix-xi	2-24-77
1-9	8-20-76
10	2-7-77
11-23	8-20-76
24	2-7-77
25-35	8-20-76
36	2-15-77
37-43	8-20-76
44	2-15-77
45-53	8-20-76
54	2-15-77
55	2-7-77
56-88	8-20-76
89-95	2-15-77
96-111	8-20-76
112	2-7-77
113-122	8-20-76
123-124	2-15-77
125-142	8-20-76
143-146	2-15-77

EFFECTIVE PAGE LISTING

PAGE	EFFECTIVE REVISION DATE
Appendix A	
147-149	8-20-76
150-151	2-15-77
152-156	8-20-76
157-158	2-15-77
159-166	8-20-76
167	2-15-76
168-170	8-20-76
171-172	3-11-77
173-186	8-20-76
187	2-15-77
188-226	8-20-76
227	2-15-77
228-251	8-20-76
252	2-15-77
253-258	8-20-76
259	2-15-77
260-261	8-20-76
262	2-15-77
263-266	8-20-76
267-270	2-15-77
271-285	8-20-76
286	2-15-77
287-294	8-20-76
295-296	2-15-77

EFFECTIVE PAGE LISTING

PAGE	EFFECTIVE REVISION PAGE
297-321	8-20-76
322	2-15-77
323-325	8-20-76
326	2-15-77
327-331	8-20-76
332-333	2-15-77
334-336	8-20-76
337	2-15-77
338-345	8-20-76
346	2-15-77
347-348	8-20-76
349-350	2-15-77
351-353	8-20-76
354	2-15-77
355	8-20-76
356-357	2-15-77
358-364	8-20-76

Appendix B

1-46	8-20-76

INTRODUCTION

This document presents the technical specifications for the Browns Ferry Nuclear Plant Unit 1 only.

1.0 DEFINITIONS

The succeeding frequently used terms are explicitly defined so that a uniform interpretation of the specifications may be achieved.

A. Safety Limit - The safety limits are limits below which the reasonable maintenance of the cladding and primary systems are assured. Exceeding such a limit requires unit shutdown and review by the Atomic Energy Commission before resumption of unit operation. Operation beyond such a limit may not in itself result in serious consequences but it indicates an operational deficiency subject to regulatory review.

B. Limiting Safety System Setting (LSSS) - The limiting safety system setting are settings on instrumentation which initiate the automatic protective action at a level such that the safety limits will not be exceeded. The region between the safety limit and these settings represent margin with normal operation lying below these settings. The margin has been establishd so that with proper operation of the instrumentation the safety limits will never be exceeded.

C. Limiting Conditions for Operation (LCO) - The limiting conditions for operation specify the minimum acceptable levels of system performance necessary to assure safe startup and operation of the facility. When these conditions are met, the plant can be operated safely and abnormal situations can be safely controlled.

D. DELETED

E. Operable - A system or component shall be considered operable when it is capable of performing its intended function in its required manner.

F. Operating - Operating means that a system or component is performing its intended functions in its required manner.

G. Immediate - Immediate means that the required action will be initiated as soon as practicable considering the safe operation of the unit and the importance of the required action.

H. Reactor Power Operation - Reactor power operation is any operation with the mode switch in the "Startup" or "Run" position with the reactor critical and above 1% rated power.

I. Hot Standby Condition - Hot standby condition means operation with coolant temperature greater than 212°F, system pressure less than 1055 psig, the main steam isolation valves closed and the mode switch in the Startup/Hot Standby position.

J. Cold Condition - Reactor coolant temperature equal to or less than 212°F.

K. Hot Shutdown - The reactor is in the shutdown mode and the reactor coolant temperature greater than 212°F.

L. Cold Shutdown - The reactor is in the shutdown mode, the reactor coolant temperature equal to or less than 212°F, and the reactor vessel is vented to atmosphere.

M. Mode of Operation - A reactor mode switch selects the proper interlocks for the operational status of the unit. The following are the modes and interlocks provided:

1. Startup/Hot Standby Mode - In this mode the reactor protection scram trips initiated by condenser low vacuum and main steam line isolation valve closure, are bypassed when reactor pressure is less than 1055 psig, the reactor protection system is energized with IRM neutron monitoring system trip, the APRM 15% high flux trip, and control rod withdrawal interlocks in service. This is often referred to as just Startup Mode. This is intended to imply the Startup/Hot Standby position of the mode switch.

2. Run Mode - In this mode the reactor system pressure is at or above 850 psig and the reactor protection system is energized with APRM protection (excluding the 15% high flux trip) and RBM interlocks in service.

3. Shutdown Mode - Placing the mode switch to the shutdown position initiates a reactor scram and power to the control rod drives is removed. After a short time period (about 10 sec), the scram signal is removed allowing a scram reset and restoring the normal valve lineup in the control rod drive hydraulic system; also, the main steam line isolation scram and main condenser low vacuum scram are bypassed if reactor vessel pressure is below 1055 psig.

4. Refuel Mode - With the mode switch in the refuel position interlocks are established so that one control rod only may be withdrawn when the Source Range Monitor indicate at least 3 cps and the refueling crane is not over the reactor; also, the main steam line isolation scram and main condenser low vacuum scram are bypassed if reactor vessel pressure is below 1055 psig. If the refueling crane is over the reactor, all rods must be fully inserted and none can be withdrawn.

N. Rated Power - Rated power refers to operation at a reactor power of 3,293 MWt; this is also termed 100 percent power and is the maximum power level authorized by the operating license. Rated steam flow, rated coolant flow, rated neutron flux, and rated nuclear system pressure refer to the values of these parameters when the reactor is at rated power. Design power, the power to which the safety analysis applies, corresponds to 3440 MWt.

O. Primary Containment Integrity - Primary containment integrity means that the drywell and pressure suppression chamber are intact and all of the following conditions are satisfied:

1. All non-automatic containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during accident conditions are closed. These valves may be opened to perform necessary operational activities.

2. At least one door in each airlock is closed and sealed.

3. All automatic containment isolation valves are operable or deactivated in the isolated position.

4. All blind flanges and manways are closed.

P. Secondary Containment Integrity - Secondary containment integrity means that the reactor building is intact and the following conditions are met:

1. At least one door in each access opening is closed.

2. The standby gas treatment system is operable.

3. All Reactor Building ventilation system automatic isolation valves are operable or deactivated in the isolated position.

Q. Operating Cycle - Interval between the end of one refueling outage for a particular unit and the end of the next subsequent refueling outage for the same unit.

R. Refueling Outage - Refueling outage is the period of time between the shutdown of the unit prior to a refueling and the startup of the unit after that refueling. For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled outage; however, where such outages occur within 8 months of the completion of the previous refueling outage, the required surveillance testing need not be performed until the next regularly scheduled outage.

S. Alteration of the Reactor Core - The act of moving any component in the region above the core support plate, below the upper grid and within the shroud. Normal control rod movement with the control rod drive hydraulic system is not defined as a core alteration. Normal movement of in-core instrumentation and the traversing in-core probe is not defined as a core alteration.

T. Reactor Vessel Pressure - Unless otherwise indicated, reactor vessel pressures listed in the Technical Specifications are those measured by the reactor vessel steam space detectors.

U. Thermal Parameters

1. Minimum Critical Power Ratio (MCPR) - Minimum Critical Power Ratio (MCPR) is the value of the critical power ratio associated with the most limiting assembly in the reactor core. Critical Power Ratio (CPR) is the ratio of that power in a fuel assembly, which is calculated to cause some point in the assembly to experience boiling transition, to the actual assembly operating power.

2. Transition Boiling - Transition boiling means the boiling regime between nucleate and film boiling. Transition boiling is the regime in which both nucleate and film boiling occur intermittently with neither type being completely stable.

3. Total Peaking Factor - The ratio of the maximum fuel rod surface heat flux in any assembly to the average surface heat flux of the core.

4. Average Planar Linear Heat Generation Rate (APLHGR) - The Average Planar Heat Generation Rate is applicable to a specific planar height and is equal to the sum of the linear heat generation rates for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

V. Instrumentation

1. Instrument Calibration - An instrument calibration means the adjustment of an instrument signal output so that it corresponds, within acceptable range, and accuracy, to a known value(s) of the parameter which the instrument monitors.

2. Channel - A channel is an arrangement of a sensor and associated components used to evaluate plant variables and produce discrete outputs used in logic. A channel terminates and loses its identity where individual channel outputs are combined in logic.

3. Instrument Functional Test - An instrument functional test means the injection of a simulated signal into the instrument primary sensor to verify the proper instrument channel response, alarm and/or initiating action.

4. Instrument Check - An instrument check is qualitative determination of acceptable operability by observation of instrument behavior during operation. This determination shall include, where possible, comparison of the instrument with other independent instruments measuring the same variable.

5. Logic System Functional Test - A logic system functional test means a test of all relays and contacts of a logic circuit to insure all components are operable per design intent. Where practicable, action will go to completion; i.e., pumps will be started and valves operated.

6. Trip System - A trip system means an arrangement of instrument channel trip signals and auxiliary equipment required to initiate action to accomplish a protective trip function. A trip system may require one or more instrument channel trip signals related to one or more plant parameters in order to initiate trip system action. Initiation of protective action may require the tripping of a single trip system or the coincident tripping of two trip systems.

7. Protective Action - An action initiated by the protection system when a limit is reached. A protective action can be at a channel or system level.

8. Protective Function - A system protective action which results from the protective action of the channels monitoring a particular plant condition.

9. Simulated Automatic Actuation - Simulated automatic actuation means applying a simulated signal to the sensor to actuate the circuit in question.

10. Logic - A logic is an arrangement of relays, contacts, and other components that produces a decision output.

    (a) Initiating - A logic that receive signals from channels and produces decision outputs to the actuation logic.

    (b) Actuation - A logic that receives signals (either from initiation logic or channels) and produces decision outputs to accomplish a protective action.

W. Functional Tests - A functional test is the manual operation or initiation of a system, subsystem, or component to verify that it functions within design tolerances (e.g., the manual start of a core spray pump to verify that it runs and that it pumps the required volume of water).

X. Shutdown - The reactor is in a shutdown condition when the reactor mode switch is in the shutdown mode position and no core alterations are being performed.

Y. Engineered Safeguard - An engineered safeguard is a safety system the actions of which are essential to a safety action required in response to accidents.

Z. Cumulative Downtime - The cumulative downtime for those safety components and systems whose downtime is limited to 7 consecutive days prior to requiring reactor shutdown shall be limited to any 7 days in a consecutive 30 day period.

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. 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 1.05 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 Scram

1. APRM Flux Scram Trip Setting (Run Mode)

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

B. Core Thermal Power Limit (Reactor Pressure $\leq$800 psia)

When the reactor pressure is less than or equal to 800 psia,

2.1 FUEL CLADDING INTEGRITY

In the event of operation with a maximum total peaking factor (MTPF) greater than the design value of 2.63 the setting shall be modified as follows:

$$S \leq \{0.66W + 54\%\} \frac{2.63}{MTPF}$$

where:

MTPF = The value of the existing maximum total peaking factor

For no combination of loop recirculation flow rate and core thermal power shall the APRM flux scram trip setting be allowed to exceed 20% of rated thermal power.

(Note: These settings assume operation within the basic thermal hydraulic design criteria. These criteria are LHGR $\leq$ 18.5 kW/ft and MCPR $\geq$ 1.25. Therefore, at full power operation is not allowed with maximum total peaking factor above 2.63 even if the scram setting is reduced. 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 to within the prescribed limits. See specification 3.5.J and 3.5.K. Surveillance requirements for maximum total peaking factor 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.

B. APRM Rod Block Trip Setting

The APRM Rod block trip setting shall be:

1.1 FUEL CLADDING INTEGRITY

or core coolant flow is less than 10% of rated, the core thermal power shall not exceed 823 MWt (about 25% of rated thermal power).

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

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

where:

S_{RB} = Rod block setting is 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)

In the event of operation with a maximum total peaking factor (MTPF) greater than the design value of 2.63 the setting shall be modified as follows:

$$S_{RB} \leq \{0.66W + 42\%\} \frac{2.63}{MTPF}$$

where:

MTPF = The value of the existing maximum total peaking factor

C. Scram and isoluation reactor low water --> ≥ 538 in. above vessel zero level

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 ≥ 550 psig

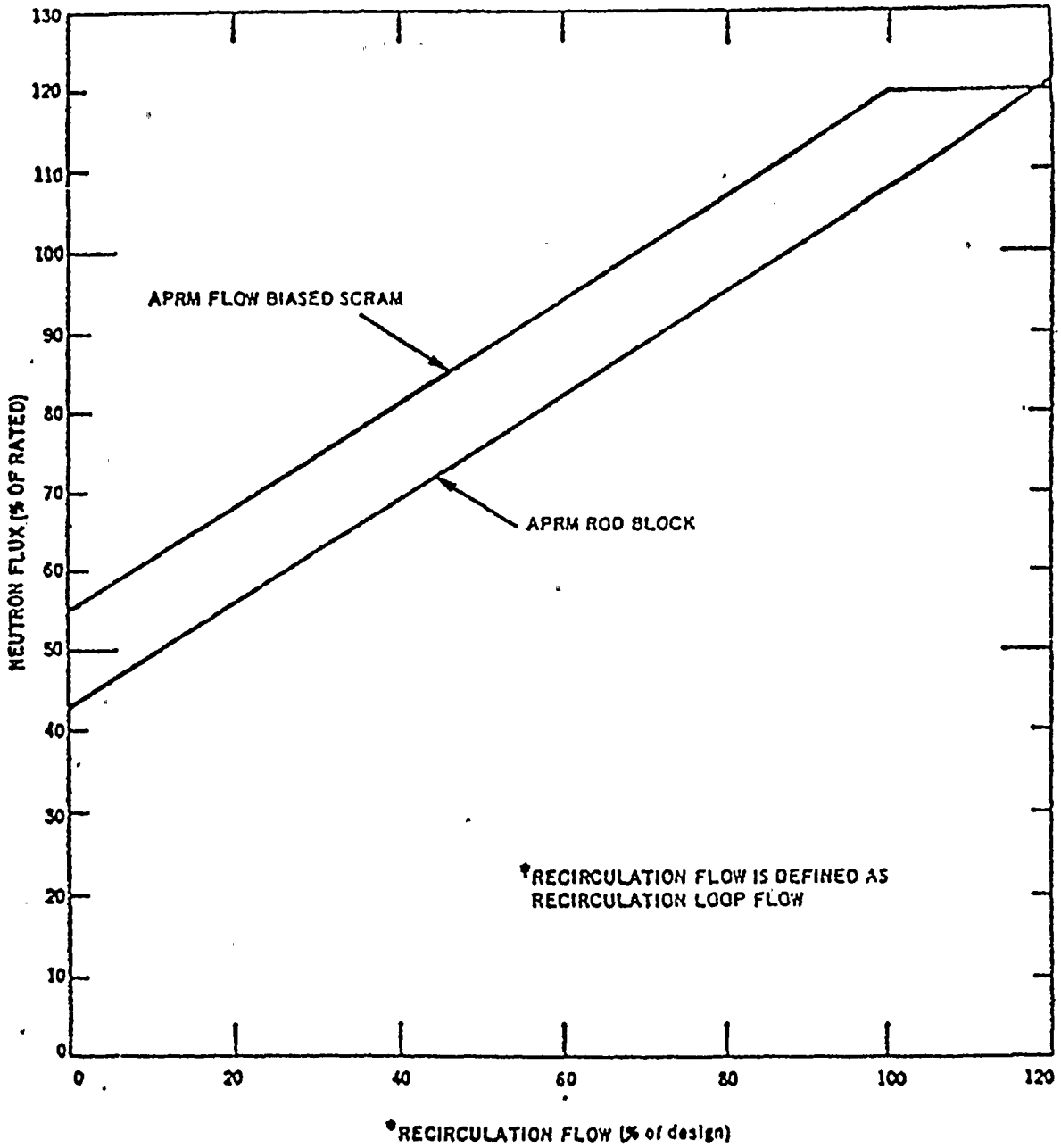
F. Scram--low condenser vacuum ≥ 23 inches Hg vacuum

G. Scram--main steam line isolation ≤ 10 percent valve closure

H. Main steam isolation valve closure--nuclear system low pressure ≥ 825 psig

SAFETY LIMIT	LIMITING SAFETY SYSTEM SETTING
1.1 Fuel Cladding Integrity	2.1 Fuel Cladding Integrity
	I. Core spray and LPCI actuation--reactor low water level: ≥ 378 in. above vesse zero
	J. HPCI and RCIC actuation--reactor low water level: ≥ 490 in. above vesse. zero
	K. Main steam isolation valve closure--reactor low water level: ≥ 490 in. above vesse. zero

FIGURE DELETED



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

APRM Flow Reference Scram
and
APRM Rod Block Settings

Figure 2.1-1

FIGURE DELETED

2.1 BASES: FUEL CLADDING INTEGRITY SAFETY LIMIT

The fuel cladding represents one of the physical barriers which separate radioactive materials from environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use-related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the protection system setpoints. While fission product migration from cladding performation is just as measurable as that from use-related cracking, the thermally-caused cladding perforations signal a threshold, beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding safety limit is defined in terms of the reactor operating conditions which can result in cladding perforation.

The fuel cladding integrity limit is set such that no calculated fuel damage would occur as a result of an abnormal operational transient. Because fuel damage is not directly observable, the fuel cladding Safety Limit is defined with margin to the conditions which would produce onset transition boiling (MCPR of 1.0). This establishes a Safety Limit such that the minimum critical power ratio (MCPR) is no less than 1.05. MCPR >1.05 represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

Onset of transition boiling results in a decrease in heat transfer from the clad and, therefore, elevated clad temperature and the possiblity of clad failure. Since boiling transition is not a directly observable parameter, the margin to boiling transition is calculated from plant operating parameters such as core power, core flow, feedwater temperature, and core power distribution. The margin for each fuel assembly is characterized by the critical power ratio (CPR) which is the ratio of the bundle power which would produce onset of transition boiling divided by the actual bundle power. The minimum value of this ratio for any bundle in the core is the minimum critical power ratio (MCPR). It is assumed that the plant operation is controlled to the nominal protective setpoints via the instrumented variables, i.e., normal plant operation presented on Figure 2.1.1 by the nominal expected flow control line. The Safety Limit (MCPR of 1.05) has sufficient conservatism to assure that in the event of an abnormal operational transient initiated from a normal operating condition (MCPR >1.25) more than 99.9% of the fuel rods in the core are expected to avoid boiling transition. The margin between MCPR of 1.0 (onset of transition boiling) and the safety limit 1.05 ____ is derived from a detailed statistical analysis considering all of the uncertainties in monitoring the core operating state including uncertainty in the boiling transition correlation as described in Reference 1. The uncertainties employed in deriving the safety limit are provided at the beginning of each fuel cycle.

The MCPR value used in the ECCS performance evaluation (1.18) is less limiting than the MCPR for operation (1.25).

1.1 BASES

Because the boiling transition correlation is based on a large quantity of full scale data there is a very high confidence that operation of a fuel assembly at the condition of MCPR = 1.05 would not produce boiling transition. Thus, although it is not required to establish the safety limit additional margin exists between the safety limit and the actual occurrence of loss of cladding integrity.

However, if boiling transition were to occur, clad perforation would not be expected. Cladding temperatures would increase to approximately 1100°F which is below the perforation temperature of the cladding material. This has been verified by tests in the General Electric Test Reactor (GETR) where fuel similar in design to BFNP operated above the critical heat flux for a significant period of time (30 minutes) without clad perforation.

If reactor pressure should ever exceed 1400 psia during normal power operating (the limit of applicability of the boiling transition correlation) it would be assumed that the fuel cladding integrity Safety Limit has been violated.

In addition to the boiling transition limit (MCPR = 1.05) operation is constrained to a maximum LHGR 18.5 Kw/ft. At 100% power this limit is reached with a maximum total peaking factor (MTPF) of 2.63. For the case of the MTPF exceeding 2.63, operation is permitted only at less than 100% of rated thermal power and only with reduced APRM scram settings as required by specification 2.1.A.1.

At pressures below 800 psia, the core elevation pressure drop (0 power, 0 flow) is greater than 4.56 psi. At low powers and flows this pressure differential is maintained in the bypass region of the core. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low powers and flows will always be greater than 4.56 psi. Analyses show that with a flow of $28X10^3$ lbs/hr bundle flow, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.56 psi driving head will be greater than $28x10^3$ lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors this corresponds to a core thermal power of more than 50%. Thus, a core thermal power limit of 25% for reactor pressures below 800 psia is conservative.

For the fuel in the core during periods when the reactor is shut down, consideration must also be given to water level requirements due to the effect of decay heat. If water level 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.

1.1 BASES

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.

PAGE DELETED

2.1 BASES: LIMITING SAFETY SYSTEM SETTINGS RELATED TO FUEL CLADDING INTEGRITY

The abnormal operational transients applicable to operation of the Browns Ferry Nuclear Plant have been analyzed throughout the spectrum of planned operating conditions up to the design thermal power condition of 3440 MWt. The analyses were based upon plant operation in accordance with the operating map given in Figure 3.7-1 of the FSAR. In addition, 3293 MWt is the licensed maximum power level of Browns Ferry Nuclear Plant, and this represents the maximum steady-state power which shall not knowingly be exceeded.

Conservatism is incorporated in the transient analyses in estimating the controlling factors, such as void reactivity coefficient, control rod scram worth, scram delay time, peaking factors, and axial power shapes. These factors are selected conservatively with respect to their effect on the applicable transient results as determined by the current analysis model. This transient model, evolved over many years, has been substantiated in operation as a conservative tool for evaluating reactor dynamic performance. Results obtained from a General Electric boiling water reactor have been compared with predictions made by the model. The comparisions and results are summarized in Reference 1.

The absolute value of the void reactivity coefficient used in the analysis is conservatively estimated to be about 25% greater than the nominal maximum value expected to occur during the core lifetime. The scram worth used has been derated to be equivalent to approximately 80% of the total scram worth of the control rods. The scram delay time and rate of rod insertion allowed by the analyses are conservatively set equal to the longest delay and slowest insertion rate acceptable by Technical Specifications.

The effect of scram worth, scram delay time and rod insertion rate, all conservatively applied, are of greatest significance in the early portion of the negative reactivity insertion. The rapid insertion of negative reactivity is assured by the time requirements for 5% and 20% insertion. By the time the rods are 60% inserted, approximately four dollars of negative reactivity has been inserted which strongly turns the transient, and accomplishes the desired effect. The times for 50% and 90% insertion are given to assure proper completion of the expected performance in the earlier portion of the transient, and to establish the ultimate fully shutdown steady-state condition.

For analyses of the thermal consequences of the transients a MCPR of 1.25 is conservatively assumed to exist prior to initiation of the transients.

This choice of using conservative values of controlling parameters and initiating transients at the design power level, produces more pessimistic answers than would result by using expected values of control parameters and analyzing at higher power levels.

Steady-state operation without forced recirculation will not be permitted, except during startup testing.

In summary:

1. The licensed maximum power level is 3,293 MWt.

2. Analyses of transients employ adequately conservative values of the controlling reactor parameters.

3. The abnormal operational transients were analyzed to a power level of 3440 MWT.

4. The analytical procedures now used result in a more logical answer than the alternative method of assuming a higher starting power in conjunction with the expected values for the parameters.

The bases for individual set points are discussed below:

A. Neutron Flux Scram

1. APRM High Flux Scram Trip Setting (Run Mode)

The average power range monitoring (APRM) system, which is calibrated using heat balance data taken during steady-state conditions, reads in percent of rated power (3,293 MWt). Because fission chambers provide the basic input signals, the APRM system responds directly to average neutron flux. During transients, the instantaneous rate of heat transfer from the fuel (reactor thermal power) is less than the instantaneous neutron flux due to the time constant of the fuel. Therefore, during transients induced by disturbances, the thermal power of the fuel will be less than that indicated by the neutron flux at the scram setting. Analyses reported in Section 14 of the Final Safety Analysis Report demonstrated that with a 120 percent scram trip setting, none of the abnormal operational transients analyzed violate the fuel safety limit and there is a substantial margin from fuel damage. Therefore, use of a flow-biased scram provides even additional margin. Figure 2.1.2 shows the flow biased scram as a function of core flow.

An increase in the APRM scram setting would decrease the margin present before the fuel cladding integrity safety limit is reached. The APRM scram setting was determined by an analysis of margins required to provide a reasonable range for maneuvering during operation. Reducing this operating margin would increase the frequency of spurious scrams, which have an adverse effect on reactor safety because of the resulting thermal stresses. Thus, the APRM setting was selected because it provides adequate margin for the fuel cladding integrity safety limit yet allows operating margin that reduces the possibility of unnecessary scrams.

The scram trip setting must be adjusted to ensure that the LHGR transient peak is not increased for any combination of MTPF and reactor core thermal power. The scram setting is adjusted in accordance with the formula in Specification 2.1.A.1, when the maximum total peaking factor is greater than 2.63.

Analyses of the limting transients show that no scram adjustment is required to assure MCPR > 1.05 when the transient is initiated from MCPR > 1.25 .

2. APRM Flux Scram Trip Setting (Refuel or Start & Hot Standby Mode)

For operation in the startup mode while the reactor is at low pressure, the APRM scram setting of 15 percent of rated power provides adequate thermal margin between the setpoint and the safety limit, 25 percent of rated. The margin is adequate to accommodate anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor, cold water from sources available during startup is not much colder than that already in the system, temperature coefficients are small, and control rod patterns are constrained to be uniform by operating procedures backed up by the rod worth minimizer and the Rod Sequence Control System. Worth of individual rods is very low in a uniform rod pattern. Thus, all of possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power rise. Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks, and because several rods must be moved to change power by a significant percentage of rated power, the rate of power rise is very slow. Generally, the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the scram level, the rate of power rise is no more than 5 percent of rated power per minute, and the APRM system would be more than adequate to assure a scram before the power could exceed the safety limit. The 15 percent APRM scram remains active until the mode switch is placed in the RUN position. This switch occurs when reactor pressure is greater than 850 psig.

3. IRM Flux Scram Trip Setting

The IRM System consists of 8 chambers, 4 in each of the reactor protection system logic channels. The IRM is a 5-decade instrument which covers the range of power level between that covered by the SRM and the APRM. The 5 decades are covered by the IRM by means of a range switch and the 5 decades are broken down into 10 ranges, each being one-half of a decade in size. The IRM scram setting of 120 divisions is active in each range of the IRM. For

3. IRM Flux Scram Trip Setting (Continued)

example, if the instrument were on range 1, the scram setting would be at 120 divisions for that range; likewise, if the instrument was on range 5, the scram setting would be 120 divisions on that range. Thus, as the IRM is ranged up to accommodate the increase in power level, the scram setting is also ranged up. A scram at 120 divisions on the IRM instruments remains in effect as long as the reactor is in the startup mode. In addition, the APRM 15% scram prevents higher power operation without being in the RUN mode. The IRM scram provides protection for changes which occur both locally and over the entire core. The most significant sources of reactivity change during the power increase are due to control rod withdrawal. For insequence control rod withdrawal, the rate of change of power is slow enough due to the physical limitation of withdrawing control rods, that heat flux is in equilibrium with the neutron flux and an IRM scram would result in a reactor shutdown well before any safety limit is exceeded. For the case of a single control rod withdrawal error, a range of rod withdrawal accidents was analyzed. This analysis included starting the accident at various power levels. The most severe case involves an initial condition in which the reactor is just subcritical and the IRM system is not yet on scale. This condition exists at quarter rod density. Quarter rod density is illustrated in paragraph 7.5.5 of the FSAR. Additional conservatism was taken in this analysis by assuming that the IRM channel closest to the withdrawn rod is bypassed. The results of this analysis show that the reactor is scrammed and peak power limited to one percent of rated power, thus maintaining MCPR above 1.05. Based on the above analysis, the IRM provides protection against local control rod withdrawal errors and continuous withdrawal of control rods in sequence.

B. APRM Control Rod Block

Reactor power level may be varied by moving control rods or by varying the recirculation flow rate. The APRM system provides a control rod block to prevent rod withdrawal beyond a given point at constant recirculation flow rate, and thus to protect against the condition of a MCPR less than 1.05. This rod block trip setting, which is automatically varried with recirculation loop flow rate, prevents an increase in the reactor power level to excess values due to control rod withdrawal. The flow variable trip setting provides substantial margin

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 maximum total peaking factor exceeds 2.63, 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 1.05 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 scram trip anticipates the pressure, neutron flux and heat flux increase that could result from rapid closure of the turbine stop valves. With a scram trip setting of $\leq$ 10 percent of valve closure from full open, the resultant increase in bundle power is limited such that MCPR remains above 1.05 even during the worst case transient that assumes the turbine bypass is closed. This scram is bypassed when turbine steam flow is below 30 percent of rated, as measured by turbine first stage pressure. Actuation of the relief valves limits pressure to well below the safety valve setting.

E. Turbine Control Valve Scram

1. Fast Closure Scram

The reactor protection system initiates a scram within 30 Msec after the control valves start to close. This setting and the fact that control valve closure time is approximately twice as long as that for the stop valves means that resulting transients, while similar, are less severe than for stop-valve closure. No fuel damage occurs, and reactor system pressure does not exceed the relief valve set point, which is approximately 280 psi below the safety limit.

2. Scram on loss of control oil pressure

The turbine hydraulic control system operates using high pressure oil. There are several points in this oil system where a loss of oil pressure could result in a fast closure of the turbine control valves. This fast closure of the turbine control valves is not protected by the generator load rejection scram, since failure of the oil system would not result in the fast closure solenoid valves being actuated. For a turbine control valve fast closure, the core would be protected by the APRM and high reactor pressure scrams. However, to provide the same margins as provided for the generator load rejection scram on fast closure of the turbine control valves, a scram has been added to the reactor protection system, which senses failure of control oil pressure to the turbine control system. This is an anticipatory scram and results in reactor shutdown before any significant increase in pressure or neutron flux occurs. The transient response is very similar to that resulting from the generator load rejection.

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 and turbine bypass 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 in

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

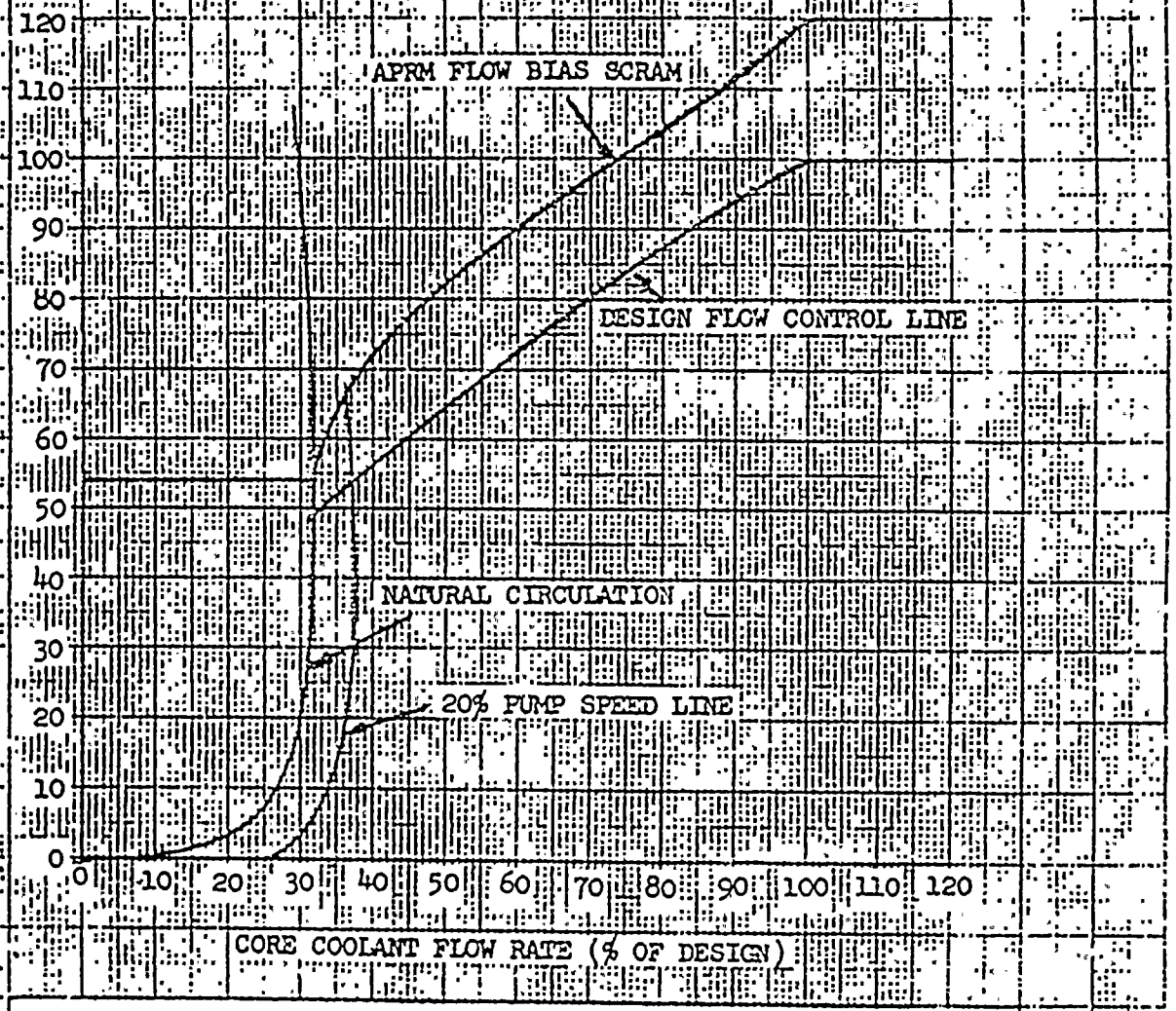
2.1 BASES

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

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 14 of the FSAR demonstrate that these conditions result in adequate safety margins for both the fuel and the system pressure.

L. References

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



APRM FLOW BIAS SCRAM Vs. REACTOR CORE FLOW
FIG. 2.1-2

SAFETY LIMIT

1.2 REACTOR COOLANT SYSTEM INTEGRITY

Applicability

Applies to limits on reactor coolant system pressure

Objective

To establish a limit below which the integrity of the reactor coolant system is not threatened due to an overpressure condition.

Specification

A. The pressure at the lowest point of the reactor vessel shall not exceed 1,375 psig whenever irradiated fuel is in the reactor vessel.

LIMITING SAFETY SYSTEM SETTING

2.2 REACTOR COOLANT SYSTEM 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 pressure safety limit from being exceeded.

Specification

The limiting safety system settings shall be as specified below:

Protective Action	Limiting Safety System Setting
A. Nuclear system safety valves open--nuclear system pressure	1,230 psig ± 13 psi (2 valves)
B. Nuclear system relief valves open--nuclear system pressure	1,080 psig ± 11 psi (4 valves)
	1,090 psig ± 11 psi (4 valves)
	1,100 psig ± 11 psi (3 valves)
C. Scram--nuclear system high pressure	≤ 1,055 psig

1.2 BASES

REACTOR COOLANT SYSTEM INTEGRITY

The safety limits for the reactor coolant system pressure have been selected such that they are below pressures at which it can be shown that the integrity of the system is not endangered. However, the pressure safety limits are set high enough such that no foreseeable circumstances can cause the system pressure to rise over these limits. The pressure safety limits are arbitrarily selected to be the lowest transient overpressures allowed by the applicable codes, ASME Boiler and Pressure Vessel Code, Section III, and USAS Piping Code, Section B31.1.

The design pressure (1,250 psig) of the reactor vessel is established such that, when the 10 percent allowance (125 psi) allowed by the ASME Boiler and Pressure Vessel Code Section III for pressure transients is added to the design pressure, a transient pressure limit of 1,375 psig is established.

Correspondingly, the design pressure (1,148 psig for suction and 1,326 psig for discharge) of the reactor recirculation system piping are such that, when the 20 percent allowance (230 and 265 psi) allowed by USAS Piping Code, Section B31.1 for pressure transients are added to the design pressures, transient pressure limits of 1,378 and 1,591 psig are established. Thus, the pressure safety limit applicable to power operation is established at 1,375 psig (the lowest transient overpressure allowed by the pertinent codes), ASME Boiler and Pressure Vessel Code, Section III, and USAS Piping Code, Section B31.1.

The Plant Safety Analysis (paragraph 14.5.1) states that the turbine trip from high power without bypass is the most severe abnormal operational transient resulting directly in a reactor coolant system pressure increase. The reactor vessel pressure code limit of 1,375 psig given in subsection 4.2 of the safety analysis report is well above the peak pressure produced by the overpressure transient described above. Thus, the pressure safety limit applicable to power operation is well above the peak pressure that can result due to reasonably expected overpressure transients.

Higher design pressures have been established for piping within the reactor coolant system than for the reactor vessel. These increased design pressures create a consistent design which assures that, if the pressure within the reactor vessel does not exceed 1,375 psig, the pressures within the piping cannot exceed their respective transient pressure limits due to static and pump heads.

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 afety 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 14.0)

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)

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.

Thirteen safety-relief valves have been installed on each unit with a total capacity of 74% of design 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 1303 psig if a pressure scram is assumed or 1260 psig if a neutron flux scram is assumed. This results in 72 psig and 115 psig margins respectively to the code allowable overpressure limit of 1375 psig. In addition, the same event was analyzed to determine the number of installed valves which must open to limit peak pressure to 1350 psig (25 psig margin). The results of this analysis shows that seven valves must open if a neutron flux scram is assumed or ten valves must open if a pressure scram is assumed.

To meet the second design basis, the total safety-relief capacity of 74% has been divided into 61% relief (11 valves) and 13% 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 FSAR paragraph 14.5.1.2 and Figure 14.5-1. This analysis shows that the 11 relief valves limit pressure at the safety valves to 1168 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 1210 psig which is 165 psig below the allowed vessel overpressure of 1375 psig.

3.1 REACTOR PROTECTION SYSTEM

Applicability

Applies to the instrumentation and associated devices which initiate a reactor scram.

Objective

To assure the operability of the reactor protection system.

Specification

When there is fuel in the vessel, the setpoints, minimum number of trip systems, and minimum number of instrument channels that must be operable for each position of the reactor mode switch shall be as given in Table 3.1.A.

4.1 REACTOR PROTECTION SYSTEM

Applicability

Applies to the surveillance of the instrumentation and associated devices which initiate reactor scram.

Objective

To specify the type and frequency of surveillance to be applied to the protection instrumentation.

Specification

A. Instrumentation systems shall be functionally tested and calibrated as indicated in Tables 4.1.A and 4.1.B respectively.

B. Daily during reactor power operation at greater than or equal to 25% thermal power, the maximum total peaking factor shall be checked and the scram and APRM Rod Block settings given by equations in specifications 2.1.A. and 2.1.B shall be calculated.

C. When it is determined that a channel is failed in the unsafe condition, the other RPS channels that monitor the same variable shall be functionally tested immediately before the trip system containing the failure is tripped. The trip system containing the unsafe failure may be untripped for short periods of time to allow functional testing of the other trip system. The trip system may be in the untripped position for no more than eight hours per functional test period for this testing.

PAGE DELETED

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

Min. No. of Operable Inst. Channels Per Trip System (1)	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
	IRM (16)						
3	High Flux	≤ 120/125 Indicated on scale	X	X	X	(5)	1.A
3	Inoperative			X	X	(5)	1.A
	APRM (16)						
2	High Flux	See Spec. 2.1.A.1				X	1.A or 1.B
2	High Flux	≤ 15% rated power (13)		X	X(17)	(15)	1.A or 1.B
2	Inoperative			X	X(17)	X	1.A or 1.B
2	Downscale	≥ 3 Indicated on Scale		(11)	(11)	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 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 (Continued)

Min. No. of Operable Inst. Channels Per Trip System (1)	Trip Function	Trip Level Setting	Modes in Which Function Must Be Operable: 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	Upon trip of the fast acting solenoid valves	X(4)	X(4)	X(4)	1.A or 1.D
4	Turbine Stop Valve Closure	≤ 10% Valve Closure	X(4)	X(4)	X(4)	1.A or 1.D
2	Turbine Control Valve - Loss of Control Oil Pressure	≥ 550 psig	X(4)	X(4)	X(4)	1.A or 1.D
2	Turbine First Stage Pressure Permissive	≤ 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

NOTES FOR TABLE 3.1.A

1. There shall be two operable or tripped trip systems for each function. If the minimum number of operable instrument channels per trip system cannot be met for both trip systems, the appropriate actions listed below shall be taken.

   A. Initiate insertion of operable rods and complete insertion of all operable rods within four hours.

   B. Reduce power level to IRM range and place mode switch in the Startup/Hot Standby position within 8 hours.

   C. Reduce turbine load and close main steam line isolation valves within 8 hours.

   D. Reduce power to less than 30% of rated.

2. Scram discharge volume high bypass may be used in shutdown or refuel to bypass scram discharge volume scram with control rod block for reactor protection system reset.

3. Bypassed if reactor pressure < 1055 psig and mode switch not in run.

4. Bypassed when turbine first stage pressure is less than 154 psig.

5. IRM's are bypassed when APRM's are onscale and the reactor mode switch is in the run position.

6. The design permits closure of any two lines without a scram being initiated.

7. When the reactor is subcritical and the reactor water temperature is less than 212°F, only the following trip functions need to be operable:

   A. Mode switch in shutdown

   B. Manual scram

   C. High flux IRM

   D. Scram discharge volume high level

   E. APRM 15% scram

8. Not required to be operable when primary containment integrity is not required.

9. Not required if all main steamlines are isolated.

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.

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. Operability is required when normal first-stage pressure is below 30% ($\leq$ 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. An alarm setting of 1.5 times normal background at rated power shall be established to alert the operator to abnormal radiation levels in primary coolant.

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)
Mode Switch in Shutdown	A	Place Mode Switch in Shutdown	Each Refueling Outage
Manual Scram	A	Trip Channel and Alarm	Every 3 Months
IRM			
High Flux	C	Trip Channel and Alarm (4)	Once Per Week During Refuelin and Before Each Startup
Inoperative	C	Trip Channel and Alarm (4)	Once Per Week During Refuelin and Before Each Startup
APRM			
High Flux (15% scram)	C	Trip Output Relays (4)	Before Each Startup and Weekl When Required to be Operable
High Flux	B	Trip Output Relays (4)	Once/Week
Inoperative	B	Trip Output Relays (4)	Once/Week
Downscale	B	Trip Output Relays (4)	Once/Week
Flow Bias	B	(6)	(6)
High Reactor Pressure	A	Trip Channel and Alarm	Once/Month (1)
High Drywell Pressure	A	Trip Channel and Alarm	Once/Month (1)
Reactor Low Water Level (5)	A	Trip Channel and Alarm	Once/Month (1)
High Water Level in Scram Discharge Tank	A	Trip Channel and Alarm	Every 3 Months
Turbine Condenser Low Vacuum	A	Trip Channel and Alarm	Once/Month (1)
Main Steam Line High Radiation	B	Trip Channel and Alarm (4)	Once/Week

TABLE 4.1.A (Continued)

	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	A	Trip Channel and Alarm	Once/Month (1)
Turbine Control Valve - Loss of Oil Pressure	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)

NOTES FOR TABLE 4.1.A

1. Initially the minimum frequency for the indicated tests shall be once per month.

2. A description of the three groups is included in the Bases of this specification.

3. Functional tests are not required when the systems are not required to be operable or are operating (i.e., already tripped). If tests are missed, they shall be performed prior to returning the systems to an operable status.

4. This instrumentation is exempted from the instrument channel test definition. This instrument channel functional test will consist of injecting a simulated electrical signal into the measurement channels.

5. The water level in the reactor vessel will be perturbed and the corresponding level indicator changes will be monitored. This perturbation test will be performed every month after completion of the monthly functional test program.

6. The functional test of the flow bias network is performed in accordance with Table 4.2.C.

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 Shutdowns (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	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 Control Valve - Loss of Oil Pressure	A	Standard Pressure Source	Once / operating cycle
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. Maximum frequency required is once per week.

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

6. On controlled shutdowns, 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.

3.1 BASES

The reactor protection system automatically initiates a reactor scram to:

1. Preserve the integrity of the fuel cladding.

2. Preserve the integrity of the reactor coolant system.

3. Minimize the energy which must be absorbed following a loss of coolant accident, and prevents criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to tolerate single failures and still perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations.

The reactor protection system is made up of two independent trip systems (refer to Section 7.2, FSAR). There are usually four channels provided to monitor each critical parameter, with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic such that either channel trip will trip that trip system. The simultaneous tripping of both trip systems will produce a reactor scram.

This system meets the intent of IEEE - 279 for Nuclear Power Plant Protection Systems. The system has a reliability greater than that of a 2 out of 3 system and somewhat less than that of a 1 out of 2 system.

With the exception of the Average Power Range Monitor (APRM) channels, the Intermediate Range Monitor (IRM) channels, the Main Steam Isolation Valve closure and the Turbine Stop Valve closure, each trip system logic has one instrument channel. When the minimum condition for operation on the number of operable instrument channels per untripped protection trip system is met or if it cannot be met and the effected protection trip system is placed in a tripped condition, the effectiveness of the protection system is preserved; i.e., the system can tolerate a single failure and still perform its intended function of scramming the reactor. Three APRM instrument channels are provided for each protection trip system.

Each protection trip system has one more APRM than is necessary to meet the minimum number required per channel. This allows the bypassing of one APRM per protection trip system for maintenance, testing or calibration. Additional IRM channels have also been provided to allow for bypassing of one such channel. The bases for the scram setting for the IRM, APRM, high reactor pressure, reactor low water level, MSIV closure, turbine control valve fast closure, turbine stop valve closure and loss of condenser vacuum are discussed in Specification 2.1 and 2.2.

Instrumentation (pressure switches) for the drywell are provided to detect a loss of coolant accident and initiate the core standby cooling equipment. A high drywell pressure scram is provided at the same setting as the core cooling systems (CSCS) initiation to minimize the energy which must be accommodated during a loss of coolant accident and to prevent return to criticality. This instrumentation is a backup to the reactor vessel water level instrumentation.

High radiation levels in the main steam line tunnel above that due to the normal nitrogen and oxygen radioactivity is an indication of leaking fuel. A scram is initiated whenever such radiation level exceeds three times normal background. The purpose of this scram is to reduce the source of such radiation to the extent necessary to prevent release of radioactive material to the turbine. An alarm is initiated whenever ther radiation level exceeds 1.5 times normal background to alert the operator to possible serious radioactivity spikes due to abnormal core behavior. The air ejector off-gas monitors serve to back up the main steam line monitors to provide further assurance against release of radioactive materials to site environs by isolating the main condenser off-gas line to the main stack.

A reactor mode switch is provided which actuates or bypasses the various scram functions appropriate to the particular plant operating status. Ref. Section 7.2.3.7 FSAR.

The manual scram function is active in all modes, thus providing for a manual means of rapidly inserting control rods during all modes of reactor operation.

The IRM system (120/125 scram) in conjunction with the APRM system (15% scram) provides protection against excessive power levels and short reactor periods in the startup and intermediate power ranges.

The control rod drive scram system is designed so that all of the water which is discharged from the reactor by a scram can be accommodated in the discharge piping. The discharge volume tank accommodates in excess of 50 gallons of water and is the low point in the piping. No credit was taken for this volume in the design of the discharge piping as concerns the amount of water which must be accommodated during a scram. During normal operation the discharge volume is empty; however, should it fill with water, the water discharged to the piping from the reactor could not be accommodated which would result in slow scram times or partial control rod insertion. To preclude this occurrence, level switches have been provided in the instrument volume which alarm and scram the reactor when the volume of water reaches 50 gallons. As indicated above, there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or amount of insertion of the control rods. This function shuts the reactor down while sufficient volume remains to accommodate the discharge water and precludes the situation in which a scram would be required but not be able to perform its function adequately.

A source range monitor (SRM) system is also provided to supply additional neutron level information during startup but has no scram functions. Ref. Section 7.5.4 FSAR. Thus, the IRM is required in the Refuel and Startup

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, turbine control valve fast closure, and turbine control valve loss of control oil pressure, 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.

4.1 BASES

The minimun functional testing frequency used in this specification is based on a reliability analysis using the concepts developed in reference (1). This concept was specifically adapted to the one out of two taken twice logic of the reactor protection system. The analysis shows that the sensors are primarily responsible for the reliability of the reactor protection system. This analysis makes use of "unsafe failure" rate experience at conventional and nuclear power plants in a reliability model for the system. An "unsafe failure" is define as one which negates channel operability and which, due to its nature, is revealed only when the channel is functionally tested or attempts to respond to a real signal. Failures such as blown fuses, ruptured bourdon tubes, faulted amplifiers, faulted cables, etc., which result in "upscale" or "downscale" readings on the reactor instrumentation are "safe" and will be easily recognized by the operators during operation because they are revealed by an alarm or a scram.

The channels listed in Tables 4.1.A and 4.1.B are divided into three groups for functional testing. These are:

A. On-Off sensors that provide a scram trip function.

B. Analog devices coupled with bi-stable trips that provide a scram function.

C. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed at shutdown.

The sensors that make up group (A) are specifically selected from among the whole family of industrial on-off sensors that have earned an excellent reputation for reliable operation. During design, a goal of 0.99999 probability of success (at the 50% confidence level) was adopted to assure that a balanced and adequate design is achieved. The probability of success is primarily a function of the sensor failure rate and the test interval. A three-month test interval was planned for group (A) sensors. This is in keeping with good operating practices, and satisfies the design goal for the logic configuration utilized in the Reactor Protection System.

To satisfy the long-term objective of maintaining an adequate level of safety throughout the plant lifetime, a minimum goal of 0.9999 at the 95% confidence level is proposed. With the (1 out of 2) X (2) logic, this requires that each sensor have an availability of 0.993 at the 95% confidence level. This level of availability may be maintained by adjusting the test interval as a function of the observed failure history. (1)

---

1. Reliability of Engineered Safety Features as a Function of Testing Frequency, I. M. Jacobs, "Nuclear Safety," Vol. 9, No. 4, July-August, 1968, pp. 310-312.

4.1 BASES

To facilitate the implementation of this technique, Figure 4.1.1 is provided to indicate an appropriate trend in test interval. The procedure is as follows:

1. Like sensors are pooled into one group for the purpose of data acquisition.

2. The factor M is the exposure hours and is equal to the number of sensors in a group, n, times the elapsed time T ($M = nT$).

3. The accumulated number of unsafe failures is plotted as an ordinate against M as an abscissa on Figure 4.1.1.

4. After a trend is established, the appropriate monthly test interval to satisfy the goal will be the test interval to the left of the plotted points.

5. A test interval of one month will generally be used initially until a trend is established.

Group (B) devices utilize an analog sensor followed by an amplifier and a bi-stable trip circuit. The sensor and amplifier are active components and a failure is almost always accompanied by an alarm and an indication of the source of trouble. In the event of failure, repair or substitution can start immediately. An "as-is" failure is one that "sticks" mid-scale and is not capable of going either up or down in response to an out-of-limits input. This type of failure for analog devices is a rare occurrence and is detectable by an operator who observes that one signal does not track the other three. For purpose of analysis, it is assumed that this rare failure will be detected within two hours.

The bi-stable trip circuit which is a part of the Group (B) devices can sustain unsafe failures which are revealed only on test. Therefore, it is necessary to test them periodically.

A study was conducted of the instrumentation channels included in the Group (B) devices to calculate their "unsafe" failure rates. The analog devices (sensors and amplifiers) are predicted to have an unsafe failure rate of less than 20×10^{-6} failure/hour. The bi-stable trip circuits are predicted to have unsafe failure rate of less than 2×10^{-6} failures/hour. Considering the two hour monitoring interval for the analog devices as assumed above, and a weekly test interval for the bi-stable trip circuits, the design reliability goal of 0.99999 is attained with ample margin.

The bi-stable devices are monitored during plant operation to record their failure history and establish a test interval using the curve of Figure 4.1.1. There are numerous identical bi-stable devices used throughout the plant's instrumentation system. Therefore, significant data on the failure rates for the bi-stable devices should be accumulated rapidly.

The frequency of calibration of the APRM Flow Biasing Network has been established as each refueling outage. There are several instruments which must be calibrated and it will take several hours to perform the calibration of the entire network. While the calibration is being performed, a zero flow signal will be sent to half of the APRM's resulting in a half scram and rod block condition. Thus, if the calibration were performed during operation, flux shaping would not be possible. Based on experience at other generating stations, drift of instruments, such as those in the Flow Biasing Network, is not significant and therefore, to avoid spurious scrams, a calibration frequency of each refueling outage is established.

Group (C) devices are active only during a given portion of the operational cycle. For example, the IRM is active during startup and inactive during full-power operation. Thus, the only test that is meaningful is the one performed just prior to shutdown or startup; i.e., the tests that are performed just prior to use of the instrument.

Calibration frequency of the instrument channel is divided into two groups. These are as follows:

1. Passive type indicating devices that can be compared with like units on a continuous basis.

2. Vacuum tube or semiconductor devices and detectors that drift or lose sensitivity.

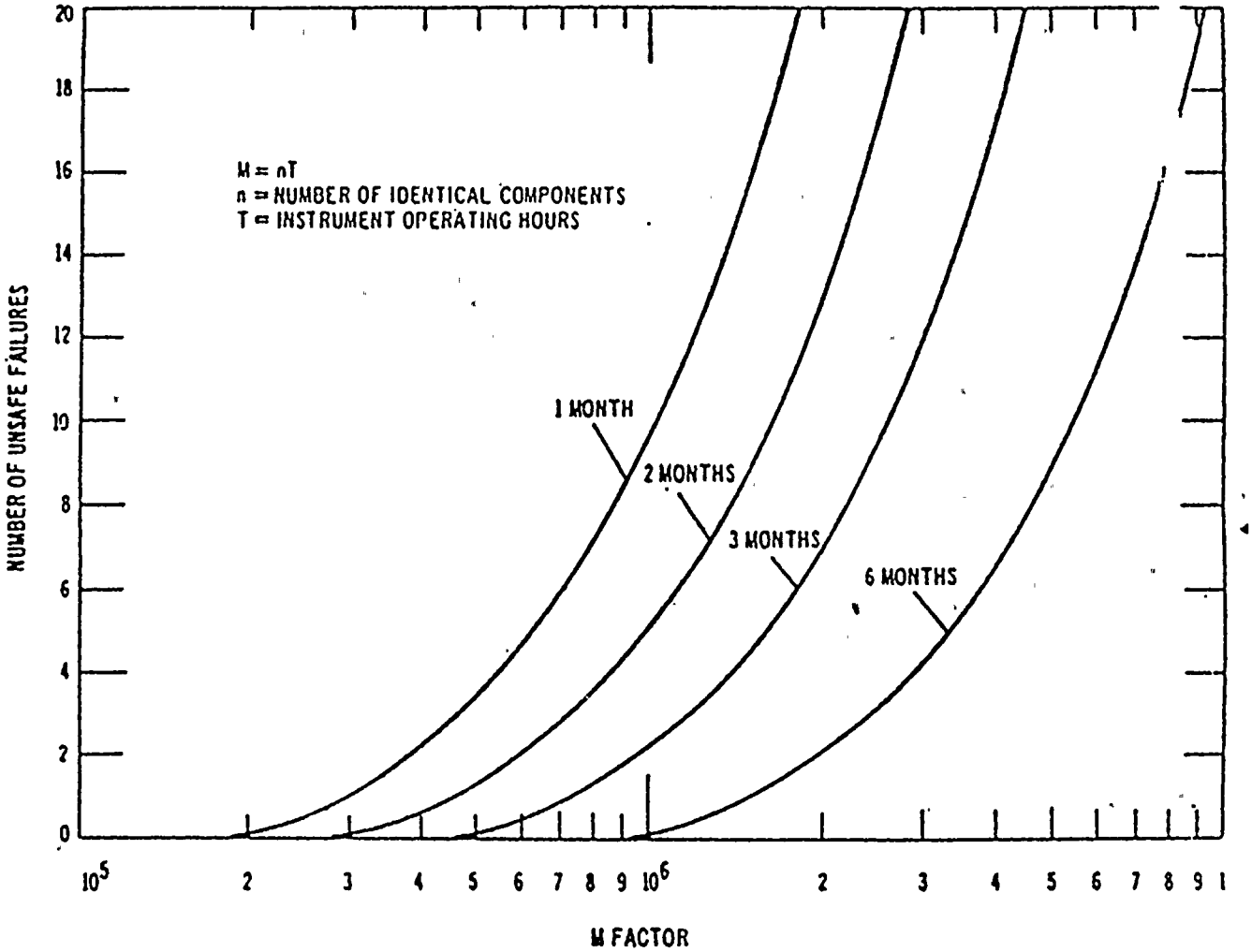
Experience with passive type instruments in generating stations and substations indicates that the specified calibrations are adequate. For those devices which employ amplifiers, etc., drift specifications call for drift to be less than 0.4%/month; i.e., in the period of a month a drift of .4% would occur and thus providing for adequate margin. For the APRM system drift of electronic apparatus is not the only consideration in determining a calibration frequency. Change in power distribution and loss of chamber sensitivity dictate a calibration every seven days. Calibration on this frequency assures plant operation at or below thermal limits.

A comparison of Tables 4.1.A and 4.1.B indicates that two instrument channels have not been included in the latter table. These are: mode switch in shutdown and manual scram. All of the devices or sensors associated with these scram functions are simple on-off switches and, hence, calibration during operation is not applicable, i.e., the switch is either on or off.

The maximum total peaking factor shall be checked out once per day to determine if the APRM scram requires adjustment. This will normally be done by checking the LPRM readings. Only a small number of control rods are moved daily

during steady-state operation and thus the peaking factors are not expected to change significantly.

The sensitivity of LPRM detectors decreases with exposure to neutron flux at a slow and approximately constant rate. This is compensated for in the APRM system by calibrating every 7 days using heat balance data and by calibrating individual LPRM's every 1000 effective full-power hours using TIP traverse data.



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

Graphical Aid in the Selection of an Adequate Interval Between Tests

Figure 4.1-1

3.2 PROTECTIVE INSTRUMENTATION

Applicability

Applies to the plant instrumentation which initates and controls a protective function.

Objective

To assure the operability of protective instrumentation.

Specification

A. Primary Containment and Reactor Building Isolation Functions

When primary containment integrity is required, the limiting conditions of operation for the instrumentation that initiates primary containment isolation are given in Table 3.2.A. This includes instrumentation that initiates isolation of the reactor vessel, reactor building, main steam lines, and initiates the standby gas treatment system.

B. Core and Containment Cooling Systems - Initiation & Control

The limiting conditions for operation for the instrumentation that initiates or controls the core and containment cooling systems are given in Table 3.2.B. This instrumentation must be operable when the system(s) it initiates or controls are required to be operable as specified in Section 3.5.

4.2 PROTECTIVE INSTRUMENTATION

Applicability

Applies to the surveillance requirement of the instrumentation that initiates and controls protective function.

Objective

To specify the type and frequency of surveillance to be applied to protective instrumentation.

Specification

A. Primary Containment and Reactor Building Isolation Functions

Instrumentation shall be functionally tested and calibrated as indicated in Table 4.2.A.

System logic shall be functionally tested as indicated in Table 4.2.A.

B. Core and Containment Cooling Systems - Initiation & Control

Instrumentation shall be functionally tested, calibrated and checked as indicated in Table 4.2.B.

System logic shall be functionally tested as indicated in Table 4.2.B.

Whenever a system or loop is made inoperable because of a required test or calibration, the other systems or loops that

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.2.B Core and Containment Cooling Systems - Initiation & Control	4.2.B Core and Containment Cooling Systems - Initiation & Control
	are required to be operable shall be considered operable if they are within the required surveillance testing frequency and there is no reason to suspect that they are inoperable.
C. Control Rod Block Actuation	C. Control Rod Block Actuation
1. The limiting conditions of operation for the instrumentation that initiates control rod block are given in Table 3.2.C.	Instrumentation shall be functionally tested, calibrated and checked as indicated in Table 4.2.C.
2. The minimum number of operable instrument channels specified in Table 3.2.C for the Rod Block Monitor may be reduced by one in one of the trip systems for maintenance and/or testing, provided that this condition does not last longer than 24 hours in any thirty day period.	System logic shall be functionally tested as indicated in Table 4.2.C.
D. Off-Gas Post Treatment Isolation Function	D. Off-Gas Post Treatment Isolation Functions
1. Off Gas Post Treatment Monitors	1. Off-Gas Post Treatment Monitoring System
(a) Except as specified in (b) below, both off-gas post treatment radiation monitors shall be operable during reactor operation. The isolation function trip settings for the monitors shall be set at a value not to exceed the equivalent of the stack release limit specified in specification 3.8.B.1.	Instrumentation shall be functionally tested, calibrated and checked as indicated in Table 4.2.D.
	System logic shall be functionally tested as indicated in Table 4.2.D.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.2.D Off-Gas Post Treatment Isolation Functions	4.2.D Off-Gas Post Treatment Isolation Function
(b) From and after the date that one of the two off-gas post treatment radiation monitors is made or found to be inoperable, continued reactor power operation is permissible during the next seven days, provided that the inoperable monitor is tripped in the downscale position. One radiation monitor may be out of service for four hours for functional test and/or calibration without the monitor being in a downscale tripped condition.	
(c) Upon the loss of both off-gas post treatment radiation monitors, initiate an orderly shutdown and shut the mainsteam isolation valves or the off-gas isolation valve within 10 hours.	
E. Drywell Leak Detection	E. Drywell Leak Detection
The limiting conditions of operation for the instrumentation that monitors drywell leak detection are given in Table 3.2.E.	Instrumentation shall be calibrated and checked as indicated in Table 4.2.E.
F. Surveillance Instrumentation	F. Surveillance Instrumentation
The limiting conditions for the instrumentation that provides surveillance information readouts are given in Table 3.2.F.	Instrumentation shall be calibrated and checked as indicated in Table 4.2.F.
G. Control Room Isolation	G. Control Room Isolation
The limiting conditions for instrumentation that isolates the control room and initiates the control room emergency pressurization systems are given in Table 3.2.G.	Instrumentation shall be calibrated and checked as indicated in Table 4.2.G.

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.D 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.

3.2.J Seismic Monitoring Instrumentation

1. The seismic monitoring instruments listed in table 3.2.J shall be operable at all times.

2. With the number of seismic monitoring instruments less than the number listed in table 3.2.J, restore the inoperable instrument(s) to operable status within 30 days.

3. With one or more of the instruments listed in table 3.2.J inoperable for more than 30 days, submit a Special Report to the Commission pursuant to specification 6.7.3.C within the next 10 days describing the cause of the malfunction and plans for restoring the instruments to operable status.

4.2.J Seismic Monitoring Instrumentation

1. Each of the seismic monitoring instruments shall be demonstrated operable by performance of tests at the frequencies listed in table 4.2.J.

2. 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 to the Commission pursuant to specification 6.7.3.D within 10 days describing the magnitude, frequency spectrum, and resultant effect upon plant features important to safety.

TABLE 3.2.A
PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Minimum No. Operable Per Trip Sys (1)	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)	≥ 490" 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 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. Operable Per Sys (1)	Function	Trip Level Setting	Action (1)	Remarks
2	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. Operable Per Trip Sys (1)	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	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. Operable Per Trip Sys (1)	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 (Continued)

Minimum No. Operable Per Trip Sys (1)	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 channels 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.

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	≥ 490" above vessel zero.	A	1. Below trip setting initiated HPCI.
2	Instrument Channel - Reactor Low Water Level	≥ 490" 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 containment spray during accident condition.
2	Instrument Channel - Drywell High Pressure (PS-64-58 E-H)	1≤ p≤ 2 psig	A	1. Below trip setting prevents inadvertent operation of containment spray during accident conditions.

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
2	Instrument Channel - Drywell High Pressure (PS-64-58 A-D, SW #2)	≤ 2 psig	A	1. Above trip setting in conjunction wi low reactor pressure initiates CSS. Multiplier relays initiate HPCI. 2. Multiplier relay from CSS initiates accident signal.(15).
2	Instrument Channel - Reactor Low Water Level (LS-3-56A, B, C, D)	≥ 490" above vessel zero	A	1. Below trip setting trips recirculation pumps
2	Instrument Channel Reactor High Pressure (PS-3-204 A, B, C, D)	≤ 1120 psig	A	1. Above trip setting trips recirculation pumps
2	Instrument Channel - Drywell High Pressure (PS-64-58A-D, SW #1)	≤ 2 psig	A	1. Above trip setting in conjunction wi low reactor pressure initiates LPCI.
2(16)	Instrument Channel - Drywell High Pressure (PS-64-57A-D)	≤ 2 psig	A	1. Above trip setting in conjunction wi low reactor water level, drywell hig pressure, 120 sec. delay timer and C or RHR pump running, initiates ADS.
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.

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
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 2. 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 A3, B1, C3, and D1 Timers	$13 \leq t \leq 15$ sec.	A	1. With diesel power 2. One per pump
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 A3, B1, C3, and D1 Timers	$27 \leq t \leq 29$ sec.	A	1. With normal power 2. One per pump

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
1(16)	ADS Timer	120 sec ±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 ±10 psig	A	1. Below trip setting defers ADS actuation.
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.
	RHR (LPCI) Trip System bus power monitor	N/A	C	1. Monitors availability of power to logic systems.

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
1	Core Spray Trip System bus power monitor	N/A	C	1. Monitors availability of power to logic systems.
1	ADS Trip System bus power monitor	N/A	C	1. Monitors availability of power to logic systems and valves.
1	HPCI Trip System bus power monitor	N/A	C	1. Monitors availability of power to logic systems.
1	RCIC Trip System bus power monitor	N/A	C	1. Monitors availability of power to logic systems.
1(2)	Instrument Channel - Condensate Storage Tank Low Level (LS-73-56A & B)	$\geq$ Elev. 551'	A	1. Below trip setting will open HPCI suction valves to the suppression chamber.
1(2)	Instrument Channel - Suppression Chamber High Level	$\leq$ 7" above normal water level	A	1. Above trip setting will open HPCI suction valves to the suppression chamber.
2(2)	Instrument Channel - Reactor High Water Level	$\leq$ 583" above vessel zero.	A	1. Above trip setting trips RCIC turbine.
1	Instrument Channel - RCIC Turbine Steam Line High Flow	$\leq$ 450" H_2O (7)	A	1. Above trip setting isolates RCIC system and trips RCIC turbine.

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
4(4)	Instrument Channel - RCIC Steam Line Space High Temperature	≤ 200°F.	A	1. Above trip setting isolates RCIC system and trips RCIC turbine.
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.

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
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	
1	RHR (LPCI) System (Containment Cooling Spray) Logic	N/A	A	
1	HPCI System (Initiating) Logic	N/A	B	1. Includes Group 7 valves. Refer to Table 3.7.A for list of valves.
1	HPCI System (Isolation) Logic	N/A	B	1. Includes Group 4 valves. Refer to Table 3.7.A for list of valves.
1	Core Spray System auto initiation inhibit (Core Spray auto initiation).	N/A	B	1. Inhibit due to the core spray system of another unit. 2. The inhibit is considered the contact in the auto initiating logic only; i.e. the permissive function of the inhibi
1	LPCI System auto initiation inhibit (LPCI auto initiation)	N/A	B	1. Inhibit due to the LPCI System of another unit. 2. The inhibit is considered the contact in the auto initiating logic only, i.e. the permissive function of the inhibit

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
5q				
1(3)	Core Spray Loop A Discharge Pressure (PI-75-20)	0 - 500 psig Indicator (9)	D	1. Part of filled discharge pipe requirements. Refer to Section 4.5.
1(3)	Core Spray Loop B Discharge Pressure (PI-75-48)	0 - 500 psig Indicator (9)	D	1. Part of filled discharge pipe requirements. Refer to Section 4.5.
1(3)	RHR Loop A Discharge Pressure (PI-74-51)	0 - 450 psig Indicator (9)	D	1. Part of filled discharge pipe requirements. Refer to Section 4.5.
1(3)	RHR Loop B Discharge Pressure (PI-74-65)	0 - 450 psig Indicator (9)	D	1. Part of filled discharge pipe requirements. Refer to Section 4.5.
1(10)	Instrument Channel - RHR Start	N/A	A	1. Starts RHR area cooler fan when respective RHR motor starts.
1(10)	Instrument Channel - Thermostat (RHR Area Cooler Fan)	$\leq$ 100°F	A	1. Above trip setting starts RHR area cooler fans.
2(10)	Instrument Channel - Core Spray A or C Start	N/A	A	1. Starts Core Spray area cooler fan when Core Spray motor starts
2(10)	Instrument Channel - Core Spray B or D	N/A	A	1. Starts Core Spray area cooler fan when Core Spray motor starts
1(10)	Instrument Channel - Thermostat (Core Spray Area Cooler Fan)	$\leq$ 100°F	A	1. Above trip setting starts Core Spray area cooler fans

TABLE 3.2.B (Continued)

Minimum No. Operable Per Trip Sys (1)	Function	Trip Level Setting	Action	Remarks
1(10)	RHR Area Cooler Fan Logic	N/A	A	
1(10)	Core Spray Area Cooler Fan Logic	N/A	A	
1(11)	Instrument Channel - Core Spray Motors A or D Start	N/A	A	1. Starts RHRSW pumps A3 & D1
1(11)	Instrument Channel - Core Spray Motors B or C Start	N/A	A	1. Starts RHRSW pumps B1 & C3
1(12)	Instrument Channel - Core Spray Loop 1 Accident Signal (15)	N/A	A	1. Starts RHRSW pumps A3 & C3
1(12)	Instrument Channel - Core Spray Loop 2 Accident Signal (15)	N/A	A	1. Starts RHRSW pumps B1 & D1
1(13)	RHRSW Initiate Logic	N/A	(14)	

NOTES FOR TABLE 3.2.B

1. Whenever any CSCS System is required by section 3.5 to be operable, there shall be two operable trip systems except as noted. If a requirement of the first column is reduced by one, the indicated action shall be taken. If the same function is inoperable in more than one trip system or the first column reduced by more than one, action B shall be taken.

   Action:

   A. Repair in 24 hours. If the function is not operable in 24 hours, take action B.

   B. Declare the system or component inoperable.

   C. Immediately take action B until power is verified on the trip system.

   D. No action required, indicators are considered redundant.

2. In only one trip system.

3. Not considered in a trip system.

4. Requires one channel from each physical location (there are 4 locations) in the steam line space.

5. With diesel power, each RHRS pump is scheduled to start immediately and each CSS pump is sequenced to start about 7 sec later.

6. With normal power, one CSS and one RHRS pump is scheduled to start instantaneously, one CSS and one RHRS pump is sequenced to start after about 7 sec with similar pumps starting after about 14 sec and 21 sec, at which time the full complement of CSS and RHRS pumps would be operating.

7. The RCIC and HPCI steam line high flow trip level settings are given in terms of differential pressure. The RCICS setting of 450" of H_2O corresponds to 300% of rated steam flow at 1140 psia and 210% at 165 psia. The HPCIS setting of 90 psi corresponds to 225% of rated flow at 1140 psia and 160% at 165 psia.

8. Note 1 does not apply to this item.

9. The head tank is designed to assure that the discharge piping from the CS and RHR pumps are full. The pressure shall be maintained at or above the values listed in 3.5.1, which ensures water in the discharge piping and up to the head tank.

NOTES FOR TABLE 3.2.B (Continued)

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 ($\geq$ 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.

TABLE 3.2.C
INSTRUMENTATION THAT INITIATES ROD BLOCKS

Minimum No. Operable Per Trip Sys (5)	Function	Trip Level Setting
2(1)	APRM Upscale (Flow Bias)	$\leq$ 0.66W + 42% (2)
2(1)	APRM Upscale (Startup Mode) (8)	$\leq$ 12%
2(1)	APRM Downscale (9)	$\geq$ 3%
2(1)	APRM Inoperative	(10_b)
1(7)	RBM Upscale (Flow Bias)	$\leq$ 0.66W + 41% (2)
1(7)	RBM Downscale (9)	$\geq$ 3%
1(7)	RBM Inoperative	(10_c)
3(1)	IRM Upscale (8)	$\leq$ 108/125 of full scale
3(1)	IRM Downscale (3)(8)	$\geq$ 5/125 of full scale
3(1)	IRM Detector not in Startup Position (8)	(11)
3(1)	IRM Inoperative (8)	(10^a)
2(1)(6)	SRM Upscale (8)	$\leq 1 \times 10^5$ counts/sec.
2(1)(6)	SRM Downscale (4)(8)	$\geq$ 3 counts/sec.
2(1)(6)	SRM Detector not in Startup Position (4)(8)	(11)
2(1)(6)	SRM Inoperative (8)	(10a)
2(1)	Flow Bias Comparator	$\leq$ 10% difference in recirculation flows
2(1)	Flow Bias Upscale	$\leq$ 110% recirculation flow
1(1)	Rod Block Logic	N/A
2(1)	RSCS Restraint (PS-85-61A & PS-85-61B)	147 psig turbine first stage pressure (approximately 30% power)

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). Total peaking factors greater than 2.63 are 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. This function is bypassed when the count rate is $\geq$ 100 cps and IRM above range 2.

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.

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 trip is bypassed when the reactor power is $\leq$ 30%.

8. This function is bypassed when the mode switch is placed in Run.

9. This function is only active when the mode switch is in Run. This function is automatically bypassed when the IRM instrumentation is operable and not high.

10. The inoperative trips are produced by the following functions:

    a. SRM and IRM

       (1) Local "operate-calibrate" switch not in operate.

       (2) Power supply voltage low.

       (3) Circuit boards not in circuit.

    b. APRM

       (1) Local "operate-calibrate" switch not in operate.

       (2) Less than 14 LPRM inputs.

       (3) Circuit boards not in circuit.

c. RBM

(1) Local "operate-calibrate" switch not in operate.

(2) Circuit boards not in circuit.

(3) RBM fails to null.

(4) Less than required number of LPRM inputs for rod selected.

11. Detector traverse is adjusted to 114 $\pm$ 2 inches, placing the detector lower position 24 inches below the lower core plate.

TABLE 3.2.D
OFF-GAS POST TREATMENT ISOLATION INSTRUMENTATION

Min. No. Operable (1)	Function	Trip Level Setting	Action (2)	Remarks
2	Off-Gas Post Treatment Monitor	Note 3	A or B	1. 2 upscales, or 1 downscal and 1 upscale, or 2 downscales will isolate off-gas line.
1	Off-Gas Post Treatment Isolation	Note 3	B	1. One trip system with auto transfer to another source

NOTES:

1. Whenever the minimum number operable cannot be met, the indicated action shall be taken.
2. Action
   A. Refer to Section 3.2.D.1.b
   B. Refer to Section 3.2.D.1.c
3. Trip setting to correspond to Specification 3.2.D.1.a

TABLE 3.2.E
INSTRUMENTATION THAT MONITORS LEAKAGE INTO DRYWELL

System (2)	Setpoints		Action	Remarks
Equipment Drain			(1)	1. Used to determine identifiable reactor coolant leakage.
Flow Integrator	N/A			2. Considered part of sump system.
Sump Fill Rate Timer	≥20.1 min.			
Sump Pump Out Rate Timer	≤13.4 min.			
Floor Drain			(1)	1. Used to determine unidentifiable reactor coolant leakage.
Flow Integrator	N/A			2. Considered part of sump system.
Sump Fill Rate Timer	≥80.4 min.			
Sump Pump Out Rate Timer	≤8.9 min.			
Drywell Air Sampling	Gas and Particulate	3 x Average Background	(3)	

NOTES:

(1) Whenever a system is required to be operable, there shall be one operable system either automatic or manual, or the action required in Section 3.6.C.2 shall be taken.

(2) An alternate system to determine the leakage flow is a manual system whereby the time between sump pump starts is monitored. The time interval will determine the leakage flow because the volume of the sump will be known.

(3) Upon receipt of alarm, immediate action will be taken to confirm the alarm and assess the possibility of increased leakage.

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 -107.5" to +107.5"	(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	NA	Control Rod Position	6V Indicating Lights	
1	NA	Neutron Monitoring	SRM, IRM, LPRM 0 to 100% power	(1) (2) (3) (4)
1	PS-64-67	Drywell Pressure	Alarm at 35 psig	
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 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 3.2.F

Surveillance Instrumentation

Minimum # of Operable Instrument Channels	Instrument #	Instrument	Type Indication and Range	Notes
2	H_2M - 76 - 37	Drywell H_2	0.1 - 20%	(1)
	H_2M - 76 - 39	Concentration		
2	O_2M - 76 - 43	Drywell O_2		
	O_2M - 76 - 41	Concentration	0.1 - 25%	(1)
1	H_2M - 76 - 38	Suppression Chamber H_2 Concentration	0.1 - 20%	(1) (4)
1	O_2M - 76 - 42	Suppression Chamber O_2 Concentration	0.1 - 20%	

NOTES FOR TABLE 3.2.F

(1) From and after the date that one of these parameters is reduced to one indication, continued operation is permissible during the succeeding thirty days unless such instrumentation is sooner made operable.

(2) From and after the date that one of these parameters is not indicated in the control room, continued operation is permissible during the succeeding seven days unless such instrumentation is sooner made operable.

(3) If the requirements of notes (1) and (2) cannot be met, either the requirements of 3.5.H shall be complied with or an orderly shutdown shall be initiated and the reactor shall be in a Cold Condition within 24 hours.

(4) These surveillance instruments are considered to be redundant to each other.

TABLE 3.2.G
CONTROL ROOM ISOLATION INSTRUMENTATION

Minimum # of Operable Instrument Channels	Function	Trip Level Setting	Action	Remarks
2	Control room air supply duct Radiation monitors (RM-90-259 A & B)	270 cpm above background (4)	(2)	1. Monitors located in normal control room air supply ducts. 2. Also initiates control room emergency pressurization system.
(3)	Accident signal (3)	N/A	(3)	

NOTES

(1) Whenever the minimum number operable cannot be met the indicated action shall be taken.

(2) Action -

One channel inoperable - Repair as soon as possible and functionally test the other channel daily.

Two channels inoperable - Repair as soon as possible. Functionally test the control room particulate monitor (RM-90-53) and radiation monitor (RM-90-8) once per shift. These monitors alarm in the control room on high activity. This will allow the operator to manually isolate the control room and manually initiate the emergency pressurization system. If one air supply duct radiation monitor is not operable within 30 days, declare the system initiated by these monitors inoperable and take action as specified in section 3.7.E.

(3) Any signal that isolates primary containment also isolates the control room and initiates the control room emergency pressurization system. These signals and the appropriate action to take if the instrumentation is unavailable is indicated in Table 3.2.A.

(4) These monitors are set to trip at 270 cpm above background, which is a radiation level corresponding to about 10^{-5} uci/cc of Xenon-133 (about 1 mRem/hr). The initial set point is based on manufacturers empirical formulas. This setpoint will be verified by site operating personnel.

TABLE 3.2.H
FLOOD PROTECTION INSTRUMENTATION

Minimum No. of Operable Instrument Channels	Instrument Number	Instrument Function	Trip Setting	Notes
2	LS-23-75 A&B	Reservoir Level Monitoring	Elevation 564	(1), (2), (3)

NOTES

(1) From and after the date that the number of operable instrument channels is reduced to one, continued operation is permissible only during the succeeding 30 days unless such instrumentation is sooner made operable or unless the manual surveillance program is initiated, see Note (4).

(2) From and after the date that neither of these instrument channels is operable, continued operation is permissible only during the succeeding 7 days unless such instrumentation is sooner made operable or unless the manual surveillance program is initiated, see Note (4).

(3) If the requirements of Notes (1) and (2) above cannot be met, an orderly shutdown shall be initiated and all reactors shall be placed in a cold condition within 24 hours.

(4) The manual surveillance program requires that the reservoir level be monitored by plant personnel every 8 hours.

Table 3.2.I
Meteorological Monitoring Instrumentation

INSTRUMENT			INSTRUMENT ACCURACY	MINIMUM OPERABLE
1. WIND SPEED				
a. Channel A	Elevation	620 MSL	Note #1	1
b. Channel B	Elevation	737 MSL	Note #1	1
c. Channel C	Elevation	887 MSL	Note #1	1
2. WIND DIRECTION				
a. Channel A	Elevation	620 MSL	± 5°	1
b. Channel B	Elevation	737 MSL	± 5°	1
c. Channel C	Elevation	887 MSL	± 5°	1
3. AIR TEMPERATURE - DELTA T				
a. Channel A	Elevation	620-737 MSL	0.1° C	1
b. Channel B	Elevation	620-887 MSL	0.1° C	1

Note #1 Starting speed of anemometer shall be < 1 mph. Accuracy is within ± 1% of mph reading or 0.15 mph, whichever is greater.

Table 3.2.J

Seismic Monitoring Instrumentation

INSTRUMENT	MEASUREMENT RANGE	SETPOINT	MINIMUM OPERABLE
TRIAXIAL TIME HISTORY ACCELOGRAPHS			
a. U-1 reactor bldg. base slab (El. 519.0)	0-1.0g	.01g	1
b. U-1 reactor bldg. floor slab (El. 621.25)	0-1.0g	.01g	1
c. Diesel-gen. bldg. base slab (El. 565.5)	0-1.0g	.01g	1
TRIAXIAL PEAK ACCELOGRAPHS			
a. U-1 RBCCW, 10" pipe (El. 625.75)	0-5.0g	NA	1
b. U-1 RHRSW, 16" pipe (El. 580.0)	0-5.0g	NA	1
c. U-1 core spray system, 14" pipe (El. 544.0)	0-5.0g	NA	1
BIAXIAL SEISMIC SWITCHES			
a. U-1 reactor bldg. base slab	.025-.25g	0.1g	1*
b. U-1 reactor bldg. base slab	.025-.25g	0.1g	1*
c. U-1 reactor bldg. base slab	.025-.25g	0.1g	1*

* With control room indication

TABLE 4.2.A
SURVEILLANCE REQUIREMENTS FOR PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Function	Functional Test	Calibration Frequency	Instrument Check
Instrument Channel - Reactor Low Water Level (LIS-3-203A-D, SW 2-3)	(1)	(5)	once/day
Instrument Channel - Reactor High Pressure	(1)	once/3 months	none
Instrument Channel - Reactor Low Water Level (LIS-3-56A-D, SW #1)	(1)	once/3 month	once/day
Instrument Channel - High Drywell Pressure (PS-64-56A-D)	(1)	(5)	N/A
Instrument Channel - High Radiation Main Steam Line Tunnel	(1)	(5)	once/day
Instrument Channel - Low Pressure Main Steam Line	(1)	once/3 months	none
Instrument Channel - High Flow Main Steam Line	(1)	once/3 months	once/day
Instrument Channel - Main Steam Line Tunnel High Temperature	(1)	once/operating cycle	none
Instrument Channel - Reactor Building Ventilation High Radiation - Reactor Zone	(1) (14) (22)	once/3 months	once/day (8)

TABLE 4.2.A
SURVEILLANCE REQUIREMENTS FOR PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Function	Functional Test	Calibration Frequency	Instrument Check
Instrument Channel - Reactor Building Ventilation High Radiation - Refueling Zone	(1) (14) (22)	once/3 months	once/day (8)
Instrument Channel - SGTS Train A Heaters	(4)	(9)	N/A
Instrument Channel - SGTS Train B Heaters	(4)	(9)	N/A
Instrument Channel - SGTS Train C Heaters	(4)	(9)	N/A
Reactor Building Isolation Timer (refueling floor)	(4)	once/operating cycle	N/A
Instrument Channel - Static Pressure Control Permissive (refueling floor)	(10)	N/A	N/A
Static Pressure Control Pressure Regulator (refueling floor)	(4)	once/3 months	N/A
Reactor Building Isolation Timer (reactor zone)	(4)	once/operating cycle	N/A
Instrument Channel - Static Pressure Control Permissive (reactor zone)	(10)	N/A	N/A
Static Pressure Control Pressure Regulator (reactor zone)	(4)	once/3 months	N/A

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 2 (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

TABLE 4.2.A
SURVEILLANCE REQUIREMENTS FOR PRIMARY CONTAINMENT AND REACTOR BUILDING ISOLATION INSTRUMENTATION

Function	Functional Test	Calibration Frequency	Instrument Check
Group 6 Logic	once/operating cycle (18)	N/A	N/A
Group 8 (Initiating) Logic	Checked during channel functional test. No further test required.	N/A	N/A
Reactor Building Isolation (refueling floor) Logic	once/6 months (18)	(6)	N/A
Reactor Building Isolation (reactor zone) Logic	once/6 months (18)	(6)	N/A
SGTS Train A Logic	once/6 months (19)	N/A	N/A
SGTS Train B Logic	once/6 months (19)	N/A	N/A
SGTS Train C Logic	once/6 months (19)	N/A	N/A
Static Pressure Control (refueling floor) Logic	once/operating cycle (18)	(6)	N/A
Static Pressure Control (reactor zone) Logic	once/operating cycle (18)	(6)	N/A
Instrument Channel - Reactor Cleanup System Floor Drain High Temperature	(1)	once/operating cycle	N/A
Instrument Channel - Reactor Cleanup System Space High Temperature (23)			
a. RTD	once/operating cycle	( ) (once/operating cycle)	N/A
b. Temperature Switch	(1)	( )	

PAGES DELETED

89 thru 95

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

Function	Functional Test	Calibration	Instrument Check
Instrument Channel Reactor Low Water Level (LIS-3-58A-D)	(1)	once/3 months	once/day
Instrument Channel Reactor Low Water Level (LIS-3-184 & 185)	(1)	once/3 months	once/day
Instrument Channel Reactor Low Water Level (LITS-3-52 & 62)	(1)	once/3 months	once/day
Instrument Channel Reactor Low Water Level (LS-3-56A-D)	(1)	once/3 months	none
Instrument Channel Reactor High Pressure (PS-3-204A-D)	(1)	once/3 months	none
Instrument Channel Drywell High Pressure (PS-64-58E-H)	(1)	once/3 months	none
Instrument Channel Drywell High Pressure (PS-64-58A-D)	(1)	once/3 months	none
Instrument Channel Drywell High Pressure (PS-64-57A-D)	(1)	once/3 months	none
Instrument Channel Reactor Low Pressure (PS-3-74A & B) (PS-68-95) (PS-68-96)	(1)	once/3 months	none

TABLE 4.2.B (Continued)

Function	Functional Test	Calibration	Instrument Check
Instrument Channel Reactor Low Pressure (PS-68-93 & 94)	(1)	once/3 months	none
Instrument Channel Reactor Low Pressure (PS-3-186A & B, and PS-3-187A & B)	(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 A3, B1, C3, D1 Timers (Normal Power)	(4)	once/operating cycle	none
RHRSW A3, B1, C3, D1 Timers (Diesel Power)	(4)	once/operating cycle	none
ADS Timer	(4)	once/operating cycle	none

TABLE 4.2.B (Continued)

Function	Functional Test	Calibration	Instrument Check
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
Instrument Channel Suppression Chamber High Level	(1)	once/3 months	none
Instrument Channel Reactor High Water Level	(1)	once/3 months	once/day
Instrument Channel RCIC Turbine Steam Line High Flow	(1)	once/3 months	none
Instrument Channel RCIC Steam Line Space High Temperature	(1)	once/3 months	none

TABLE 4.2.B (Continued)

Function	Functional Test	Calibration	Instrument Check
Instrument Channel HPCI Turbine Steam Line High Flow	(1)	once/3 months	none
Instrument Channel HPCI Steam Line Space High Temperature	(1)	once/3 months	none
Core Spray System Logic	once/6 months	(6)	N/A
RCIC System (Initiating) Logic	once/6 months	N/A	N/A
RCIC System (Isolation) Logic	once/6 months	N/A	N/A
HPCI System (Initiating) Logic	once/6 months	(6)	N/A
HPCI System (Isolation) Logic	once/6 months	N/A	N/A
ADS Logic	once/6 months	(6)	N/A
LPCI (Initiating) Logic	once/6 months	(6)	N/A
LPCI (Containment Spray) Logic	once/6 months	(6)	N/A
Core Spray System Auto Initiation Inhibit (Core Spray Auto Initiation)	once/6 months (7)	N/A	N/A
LPCI Auto Initiation Inhibit (LPCI Auto Initiation)	once/6 months (7)	N/A	N/A

TABLE 4.2.B (Continued)

Function	Functional Test	Calibration	Instrument Check
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 to section 4.5.A).	N/A	N/A
Instrument Channel - Thermostat (Core Spray Area Cooler Fan)	once/ month	once/6 months	N/A

TABLE 4.__.B (Continued)

Function	Functional Test	Calibration	Instrument Check
RHR Area Cooler Fan Logic	Tested during functional test of instrument channels, RHR motor start and thermostst (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 thermostat (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
Instrument Channel - Core Spray Loop 1 Accident Signal	Tested during logic system functional test of core spray system.	N/A	N/A
Instrument Channel - Core Spray Loop 2 Accident Signal	Tested during logic system functional test of core spray system.	N/A	N/A
RHRSW Initiate Logic	once/6 months	N/A	N/A

TABLE 4.2.C

SURVEILLANCE REQUIREMENTS FOR INSTRUMENTATION THAT INITIATE ROD BLOCKS

Function	Functional Test		Calibration (17)	Instrument Check
APRM Upscale (Flow Bias)	(1)	(13)	once/3 months	once/day (8)
APRM Upscale (Startup Mode)	(1)	(13)	once/3 months	once/day (8)
APRM Downscale	(1)	(13)	once/3 months	once/day (8)
APRM Inoperative	(1)	(13)	N/A	once/day (8)
RBM Upscale (Flow Bias)	(1)	(13)	once/6 months	once/day (8)
RBM Downscale	(1)	(13)	once/6 months	once/day (8)
RBM Inoperative	(1)	(13)	N/A	once/day (8)
IRM Upscale	(1)(2)	(13)	once/3 months	once/day (8)
IRM Downscale	(1)(2)	(13)	once/3 months	once/day (8)
IRM Detector not in Startup Position	(2) (once/operating cycle)		once/operating cycle (12)	N/A
IRM Inoperative	(1)(2)	(13)	N/A	N/A
SRM Upscale	(1)(2)	(13)	once/3 months	once/day (8)
SRM Downscale	(1)(2)	(13)	once/3 months	once/day (8)
SRM Detector not in Startup Position	(2) (once/operating cycle)		once/operating cycle (12)	N/A
SRM Inoperative	(1)(2)	(13)	N/A	N/A
Flow Bias Comparator	(1)(15)		once/operating cycle (20)	N/A
Flow Bias Upscale	(1)(15)		once/3 months	N/A
Rod Block Logic	(16)		N/A	N/A
RSCS Restraint	(1)		once/3 months	N/A

TABLE 4.2.D
SURVEILLANCE REQUIREMENTS FOR OFF-GAS POST TREATMENT ISOLATION INSTRUMENTATION

Function	Functional Test	Calibration	Instrument Check
Off- Gas Post Treatment Monitor	(1)	once/3 months	once/day (8)
Off-Gas Post Treatment Isolation	once/6 months	N/A	N/A

TABLE 4.2.E

MINIMUM TEST AND CALIBRATION FREQUENCY FOR DRYWELL LEAK DETECTION INSTRUMENTATION

Function	Functional Test	Calibration	Instrument Check
Equipment Drain Sump Flow Integrator	(4)	once/6 months	once/day
Floor Drain Sump Flow Integrator	(4)	once/6 months	once/day
Air Sampling System	(1)	once/3 months	once/day
Equipment Drain Sump Fill Rate and Pumpout Rate Timers	(4)	once/operating cycle	N/A
Floor Drain Sump Fill Rate and Pumpout Rate Timers	(4)	once/operating cycle	N/A
Equipment Drain Logic	once/operating cycle	(6)	N/A
Floor Drain Logic	once/operating cycle	(6)	N/A

TABLE 4.2.F
MINIMUM TEST AND CALIBRATION FREQUENCY FOR SURVEILLANCE INSTRUMENTATION

Instrument Channel	Calibration Frequency	Instrument Check
1) Reactor Water Level	Once/6 months	Each Shift
2) Reactor Pressure	Once/6 months	Each Shift
3) Drywell Pressure	Once/6 months	Each Shift
4) Drywell Temperature	Once/6 months	Each Shift
5) Suppression Chamber Air Temperature	Once/6 months	Each Shift
6) Suppression Chamber Water Temperature	Once/6 months	Each Shift
7) Suppression Chamber Water Level	Once/6 months	Each Shift
8) Control Rod Position	NA	Each Shift
9) Neutron Monitoring	(2)	Each Shift
10) Drywell Pressure (PS-64-67)	Once/6 months	NA
11) Drywell Pressure (PS-64-58B)	Once/6 months	NA
12) Drywell Temperature (TR-64-52)	Once/6 months	NA
13) Timer (IS-64-67)	Once/6 months	NA
14) CAD Tank Level	Once/6 months	Once/day
15) Containment Atmosphere Monitors	Once/6 months	Once/day

TABLE 4.2.G
SURVEILLANCE REQUIREMENTS FOR CONTROL ROOM ISOLATION INSTRUMENTATION

Function	Functional Test	Calibration	Instrument Check
Control Room Air Supply Duct Radiation Monitors	(1)	once/3 months	once/day (8)
Control Room Isolation Logic	once/6 months	N/A	N/A
Simulated automatic actuation of control room isolation and emergency pressurization system	once/operating cycle	N/A	N/A

TABLE 4.2.H
MINIMUM TEST AND CALIBRATION FREQUENCY FOR FLOOD PROTECTION INSTRUMENTATION

Function	Functional Test	Calibration	Instrument Check
Instrument Channels			
Reservoir level monitoring	(1)	once/3 months	N/A

Table 4.2.J

Seismic Monitoring Instrument Surveillance Requirements

INSTRUMENT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
TRIAXIAL TIME HISTORY ACCELOGRAPHS			
a. Unit 1 reactor bldg. base slab (El. 519.0)	Monthly*	6 months	NA
b. Unit 1 reactor bldg. floor slab (El. 621.25)	Monthly*	6 months	NA
c. Diesel-generator bldg base slab (El. 565.5)	Monthly*	6 months	NA
BIAXIAL SEISMIC SWITCHES			
a. Unit 1 reactor bldg. base slab	Monthly*	6 months	once/operating cycle
b. Unit 1 reactor bldg. base slab	Monthly*	6 months	once/operating cycle
c. Unit 1 reactor bldg. base slab	Monthly*	6 months	once/operating cycle

*Except seismic switches

NOTES FOR TABLES 4.2.A THROUGH 4.2.H

1. Functional tests shall be performed once per month.

2. Functional tests shall be performed before each startup with a required frequency not to exceed once per week.

3. This instrumentation is excepted from the functional test definition. The functional test will consist of injecting a simulated electrical signal into the measurement channel.

4. Tested during logic system functional tests.

5. Refer to Table 4.1.B.

6. The logic system functional tests shall include a calibration once per operating cycle of time delay relays and timers necessary for proper functioning of the trip systems.

7. The functional test will consist of verifying continunity across the inhibit with a volt-ohmmeter.

8. Instrument checks shall be performed in accordance with the definition of Instrument Check (see Section 1.0, Definitions). An instrument check is not applicable to a particular setpoint, such as Upscale, but is a qualitative check that the instrument is behaving and/or indicating in an acceptable manner for the particular plant condition. Instrument check is included in this table for convenience and to indicate that an Instrument Check will be performed on the instrument. Instrument checks are not required when these instruments are not required to be operable or are tripped.

9. Calibration frequency shall be once/year.

10. Tested during logic system functional test of SGTS.

11. Portion of the logic is functionally tested during outage only.

12. The detector will be inserted during each operating cycle and the proper amount of travel into the core verified.

13. Functional test will consist of applying simulated inputs (see note 3). Local alarm lights representing upscale and downscale trips will be verified, but no rod block will be produced at this time. The inoperative trip will be initiated to produce a rod block (SRM and IRM inoperative also bypassed with the mode switch in RUN). The functions that cannot be verified to produce a rod block directly will be verified during the operating cycle.

NOTES FOR TABLES 4.2.A THROUGH 4.2.H (Continued)

14. Upscale trip is functionally tested during functional test time as required by section 4.7.B.1.a and 4.7.C.1.c.

15. The flow bias comparator will be tested by putting one flow unit in "Test" (producing 1/2 scram) and adjusting the test input to obtain comparator rod block. The flow bias upscale will be verified by observing a local upscale trip light during operation and verified that it will produce a rod block during the operating cycle.

16. Performed during operating cycle. Portions of the logic is checked more frequently during functional tests of the functions that produce a rod block.

17. This calibration consists of removing the function from service and performing an electronic calibration of the channel.

18. Functional test is limited to the condition where secondary containment integrity is not required as specified in sections 3.7.C.2 and 3.7.C.3.

19. Functional test is limited to the time where the SGTS is required to meet the requirements of section 4.7.C.1.c.

20. Calibration of the comparator requires the inputs from both recirculation loops to be interrupted, thereby removing the flow bias signal to the APRM and RBM and scramming the reactor. This calibration can only be performed during an outage.

21. Logic test is limited to the time where actual operation of the equipment is permissible.

22. One channel of either the reactor zone or refueling zone Reactor Building Ventilation Radiation Monitoring System may be administratively bypassed for a period not to exceed 24 hours for functional testing and calibration.

23. The Reactor Cleanup System Space Temperature monitors are RTD's that feed a temperature switch in the control room. The temperature switch may be tested monthly by using a simulated signal. The RTD itself is a highly reliable instrument and less frequent testing is necessary.

In addition to reactor protection instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operator's ability to control, or terminates operator errors before they result in serious consequences. This set of specifications provides the limiting conditions of operation for the primary system isolation function, initiation of the core cooling systems, control rod block and standby gas treatment systems. The objectives of the Specifications are (i) to assure the effectiveness of the protective instrumentation when required by preserving its capability to tolerate a single failure of any component of such systems even during periods when portions of such systems are out of service for maintenance, and (ii) to prescribe the trip settings required to assure adequate performance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations.

Some of the settings on the instrumentation that initiate or control core and containment cooling have tolerances explicitly stated where the high and low values are both critical and may have a substantial effect on safety. The set points of other instrumentation, where only the high or low end of the setting has a direct bearing on safety, are chosen at a level away from the normal operating range to prevent inadvertent actuation of the safety system involved and exposure to abnormal situations.

Actuation of primary containment valves is initiated by protective instrumentation shown in Table 3.2.A which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required.

The instrumentation which initiates primary system isolation is connected in a dual bus arrangement.

The low water level instrumentation set to trip at 177.7" (538" above vessel zero) above the top of the active fuel closes isolation valves in the RHR System, Drywell and Suppression Chamber exhausts and drains and Reactor Water Cleanup Lines (Group 2 and 3 isolation valves). The low reactor water level instrumentation that is set to trip when reactor water level is 129.7" (490" above vessel zero) above the top of the active fuel closes the Main Steam Line Isolation Valves and Main Steam, RCIC, and HPCI Drain Valves (Group 1 and 7). Details of valve grouping and required closing times are given in Specification 3.7. These trip settings are adequate to prevent core uncovery in the case of a break in the largest line assuming the maximum closing time.

The low reactor water level instrumentation that is set to trip when reactor water level is 129.7" (490" above vessel zero) above the top of the active fuel (Table 3.2.B) also initiate the RCIC and HPCI, provides input to the

LPCI loop selection logic 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 applicable 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.

Pressure instrumentation is provided to close the main steam isolation valves in Run Mode when the main steam line pressure drops below 825 psig.

The HPCI high flow and temperature instrumentation are provided to detect a break in the HPCI steam piping. Tripping of this instrumentation results in actuation of HPCI isolation valves. Tripping logic for the high flow is a 1 out of 2 logic, and all sensors are required to be operable.

High temperature in the vicinity of the HPCI equipment is sensed by 4 sets of 4 bimetallic temperature switches. The 16 temperature switches are arranged in 2 trip systems with 8 temperature switches in each trip system.

The HPCI trip settings of 90 psi for high flow and 200°F for high temperature are such that core uncovery is prevented and fission product release is within limits.

The RCIC high flow and temperature instrumentation are arranged the same as that for the HPCI. The trip setting of 450" H_2O for high flow and 200°F for temperature are based on the same criteria as the HPCI.

High temperature at the Reactor Cleanup System floor drain could indicate a break in the cleanup system. When high temperature occurs, the cleanup system is isolated.

The instrumentation which initiates CSCS action is arranged in a dual bus system. As for other vital instrumentation arranged in this fashion, the Specification preserves the effectiveness of the system even during periods when maintenance or testing is being performed. An exception to this is when logic functional testing is being performed.

The control rod block functions are provided to prevent excessive control rod withdrawal so that MCPR does not decrease to 1.05. The trip logic for this function is 1 out of n: e.g., any trip on one of six APRM's, eight IRM's, or four SRM's will result in a rod block.

The minimum instrument channel requirements assure sufficient instrumentation to assure the single failure criteria is met. The minimum instrument channel requirements for the RBM may be reduced by one for maintenance, testing, or calibration. This time period is only 3% of the operating time in a month and does not significantly increase the risk of preventing an inadvertent control rod withdrawal.

The APRM rod block function is flow biased and prevents a significant reduction in MCPR, especially during operation at reduced flow. The APRM provides gross core protection; i.e., limits the gross core power increase from withdrawal of control rods in the normal withdrawal sequence. The trips are set so that MCPR is maintained greater than 1.05.

The RBM rod block function provides local protection of the core; i.e., the prevention of critical power in a local region of the core, for a single rod withdrawal error from a limiting control rod pattern.

If the IRM channels are in the worst condition of allowed bypass, the sealing arrangement is such that for unbypassed IRM channels, a rod block signal is generated before the detected neutrons flux has increased by more than a factor of 10.

A downscale indication is an indication the instrument has failed or the instrument is not sensitive enough. In either case the instrument will not respond to changes in control rod motion and thus, control rod motion is prevented.

The refueling interlocks also operate one logic channel, and are required for safety only when the mode switch is in the refueling position.

For effective emergency core cooling for small pipe breaks, the HPCI system must function since reactor pressure does not decrease rapid enough to allow either core spray or LPCI to operate in time. The automatic pressure relief function is provided as a backup to the HPCI in the event the HPCI does not operate. The arrangement of the tripping contacts is such as to provide this function when necessary and minimize spurious operation. The trip settings given in the specification are adequate to assure the above criteria are met. The specification preserves the effectiveness of the system during periods of maintenance, testing, or calibration, and also minimizes the risk of inadvertent operation; i.e., only one instrument channel out of service.

Two post treatment off-gas radiation monitors are provided and, when their trip point is reached, cause an isolation of the off-gas line. Isolation is initiated when both instruments reach their high trip point or one has an upscale trip and the other a downscale trip or both have a downscale trip.

Both instruments are required for trip but the instruments are set so that any instruments are set so that the instantaneous stack release rate limit given in Specification 3.8 is not exceeded.

Four radiation monitors are provided for each unit which initiate Primary Containment Isolation (Group 6 isolation valves) Reactor Building Isolation and operation of the Standby Gas Treatment System. These instrument channels monitor the radiation in the Reactor zone ventilation exhaust ducts and in the Refueling Zone.

Trip setting of 100 mr/hr for the monitors in the Refueling Zone are based upon initiating normal ventilation isolation and SGTS operation so that none of the activity released during the refueling accident leaves the Reactor Building via the normal ventilation path but rather all the activity is processed by the SGTS.

Flow integrators and sump fill rate and pump out rate timers are used to determine leakage in the dryweil. A system whereby the time interval to fill a known volume will be utilized to provide a backup. An air sampling system is also provided to detect leakage inside the primary containment (See Table 3.2.E).

For each parameter monitored, as listed in Table 3.2.F, there are two channels of instrumentation except as noted. By comparing readings between the two channels, a near continuous surveillance of instrument performance is available. Any deviation in readings will initiate an early recalibration, thereby maintaining the quality of the instrument readings.

Instrumentation is provided for isolating the control room and initiating a pressurizing system that processes outside air before supplying it to the control room. An accident signal that isolates primary containment will also automatically isolate the control room and initiate the emergency pressurization system. In addition, there are radiation monitors in the normal ventilation system that will isolate the control room and initiate the emergency pressurization system. Activity required to cause automatic actuation is about one mRem/hr.

Because of the constant surveillance and control exercised by TVA over the Tennessee Valley, flood levels of large mangitudes can be predicted in advance of their actual occurrence. In all cases, full advantage will be taken of advance warning to take appropriate action whenever reservoir levels above normal pool are predicted; however, the plant flood protection is always in place and does not depend in any way on advanced warning. Therefore, during flood conditions, the plant will be permitted to operate until water begins to run across the top of the pumping station at elevation 565. Seismically qualified, redundant level switches each powered from a separate division of power are provided at the pumping station to give main control room indication of this condition. At that time an orderly shutdown of the plant will be initiated, although surges even to a depth of several feet over the pumping station deck will not cause the loss of the main condenser circulating water pumps.

The operability of the meteorological instrumentation ensures that sufficient meteorological data is available for estimating potential radiation dose to the public as a result of routine or accidental release of radioactive materials to the atmosphere. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public.

The operability of the seismic instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for Browns Ferry Nuclear Plant. The instrumentation provided is consistent with specific portions of the recommendations of Regulatory Guide 1.12 "Instrumentation for Earthquakes."

4.2 BASES

The instrumentation listed in Table 4.2.A through 4.2.F will be functionally tested and calibrated at regularly scheduled intervals. The same design reliability goal as the Reactor Protection System of 0.99999 is generally applies for all applications of (1 out of 2) X (2) logic. Therefore, on-off sensors are tested once/3 months, and bi-stable trips associated with analog sensors and amplifiers are tested once/week.

Those instruments which, when tripped, result in a rod block have their contacts arranged in a 1 out of n logic, and all are capable of being bypassed. For such a tripping arrangement with bypass capability provided, there is an optimum test interval that should be maintained in order to maximize the reliability of a given channel (7). This takes account of the fact that testing degrades reliability and the optimum interval between tests is approximately given by:

$$i = \sqrt{\frac{2t}{r}}$$

Where: i = the optimum interval between tests.

t = the time the trip contacts are disabled from performing their function while the the test is in progress.

r = the expected failure rate of the relays.

To test the trip relays requires that the channel be bypassed, the test made, and the system returned to its initial state. It is assumed this task requires an estimated 30 minutes to complete in a thorough and workmanlike manner and that the relays have a failure rate of 10^{-6} failures per hour. Using this data and the above operation, the optimum test interval is:

$$i = \sqrt{\frac{2(0.5)}{10^{-6}}} = 1 \times 10^{3}$$

$$= 40 \text{ days}$$

<u>For additional margin a test interval of once per month will be used initially</u>.

(7) UCRL-50451, Improving Availability and Readiness of Field Equipment Through Periodic Inspection, Benjamin Epstein, Albert Shiff, July 16, 1968, page 10, Equation (24), Lawrence Radiation Laboratory.

The sensors and electronic apparatus have not been included here as these are analog devices with readouts in the control room and the sensors and electronic apparatus can be checked by comparison with other like instruments. The checks which are made on a daily basis are adequate to assure operability of the sensors and electronic apparatus, and the test interval given above provides for optimum testing of the relay circuits.

4.2 BASES

The above calculated test interval optimizes each individual channel, considering it to be independent of all others. As an example, assume that there are two channels with an individual technician assigned to each. Each technician tests his channel at the optimum frequency, but the two technicians are not allowed to communicate so that one can advise the other that his channel is under test. Under these conditions, it is possible for both channels to be under test simultaneously. Now, assume that the technicians are required to communicate and that two channels are never tested at the same time.

Forbidding simultaneous testing improves the availability of the system over that which would be achieved by testing each channel independently. These one out of n trip systems will be tested one at a time in order to take advantage of this inherent improvement in availability.

Optimizing each channel independently may not truly optimize the system considering the overall rules of system operation. However, true system optimization is a complex problem. The optimums are broad, not sharp, and optimizing the individual channels is generally adequate for the system.

The formula given above minimizes the unavailability of a single channel which must be bypassed during testing. The minimization of the unavailability is illustrated by Curve No. 1 of Figure 4.2.1 which assumes that a channel has a failure rate of 0.1×10^{-6}/hour and 0.5 hours is require to test it. The unavailability is a minimum at a test interval i, of 3.16×10^{3} hours.

If two similar channels are used in a 1 out of 2 configuration, the test interval for minimum unavailability changes as a function of the rules for testing. The simplest case is to test each one independent of the other. In this case, there is assumed to be a finite probability that both may be bypassed at one time. This case is shown by Curve No. 2. Note that the unavailability is lower as expected for a redundant system and the minimum occurs at the same test interval. Thus, if the two channels are tested independently, the equation above yields the test interval for minimun unavailability.

A more usual case is that the testing is not done independently. If both channels are bypassed and tested at the same time, the result is shown in Curve No. 3. Note that the minimum occurs at about 40,000 hours, much longer than for cases 1 and 2. Also, the minimum is not nearly as low as Case 2 which indicates that this method of testing does not take full advantage of the redundant channel. Bypassing both channels for simultaneous testing should be avoided.

The most likely case would be to stipulate that one channel be bypassed, tested, and restored, and then immediately following, the second channel be bypassed, tested, and restored. This is shown by Curve No. 4. Note that

there is no true minimum. The curve does have a definite knee and very little reduction in system unavailability is achieved by testing at a shorter interval than computed by the equation for a single channel.

The best test procedure of all those examined is to perfectly stagger the tests. That is, if the test interval is four months, test one or the other channel every two months. This is shown in Curve No. 5. The difference between Cases 4 and 5 is negligible. There may be other arguments, however, that more strongly support the perfectly staggered tests, including reductions in human error.

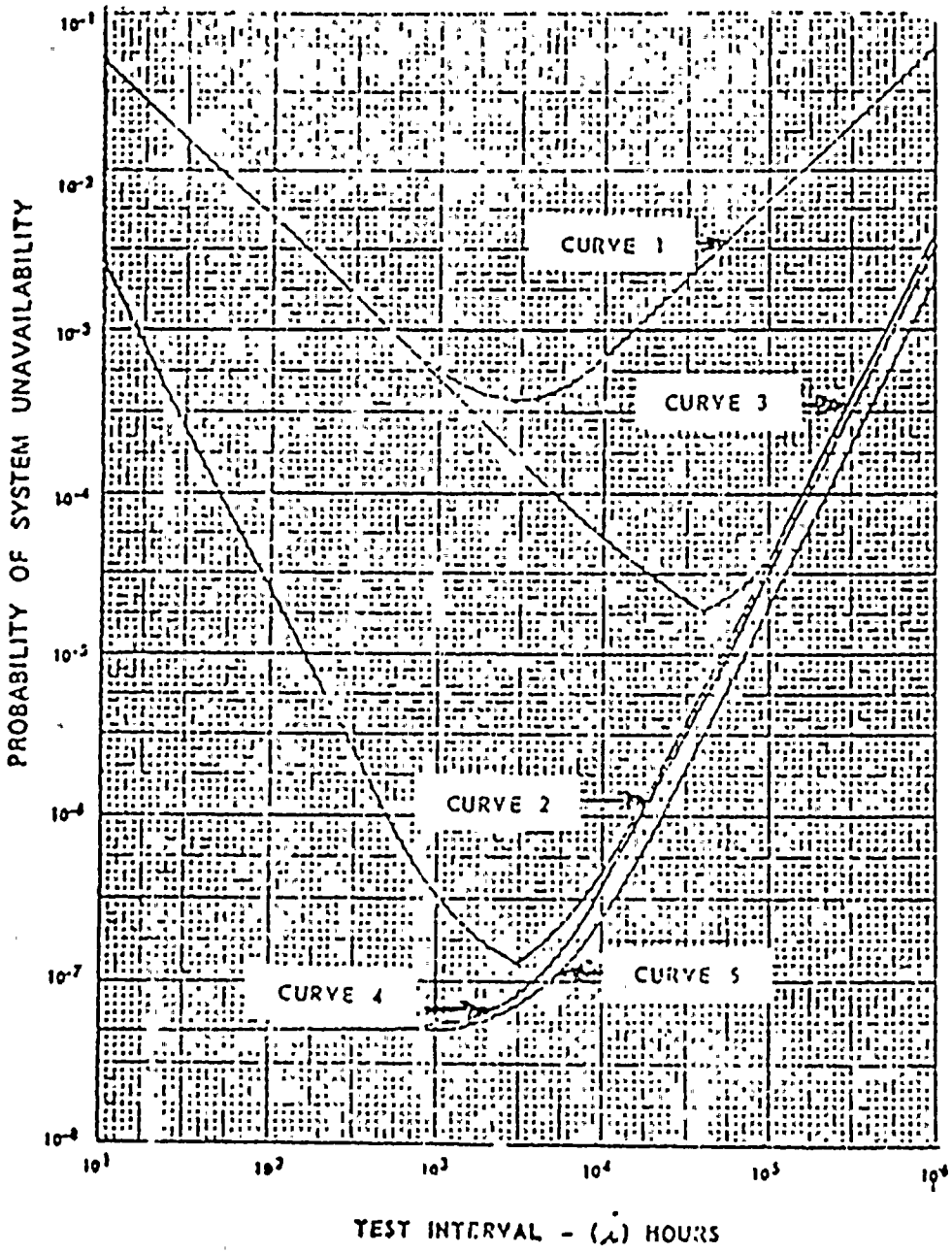
The conclusions to be drawn are these:

1. A 1 out of n system may be treated the same as a single channel in terms of choosing a test interval; and

2. more than one channel should not be bypassed for testing at any one time.

The radiation monitors in the refueling area ventilation duct which initiate building isolation and standby gas treatment operation are arranged in two 1 out of 2 logic systems. The bases given for the rod blocks apply here also and were used to arrive at the functional testing frequency. The off-gas post treatment monitors are connected in a 2 out of 2 logic arrangement. Based on experience with instruments of similar design, a testing interval of once every three months has been found adequate.

The automatic pressure relief instrumentation can be considered to be a 1 out of 2 logic system and the discussion above applies also.



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

System Unavailability

Figure 4.2-1

3.3 REACTIVITY CONTROL

Applicability:

Applies to the operational status of the control rod system

Objective:

To assure the ability of the control rod system to control reactivity.

Specification:

A. Reactivity Limitations

1. Reactivity margin - core loading

   A sufficient number of control rods shall be operable so that the core could be made subcritical in the most reactive condition during the operating cycle with the strongest control rod fully withdrawn and all other operable control rods fully inserted.

2. Reactivity margin - inoperable control rods

   a. Control rod drives which cannot be moved with control rod drive pressure shall be considered inoperable. If a partially or fully withdrawn control rod drive cannot be moved with drive or scram pressure the reactor shall be brought to the Cold Shutdown condition within 24 hours and shall not be started unless (1) investigation has demonstrated that the cause of the failure is not a failed control rod drive mechanism collet housing and (2) adequate shutdown margin has been demonstrated as required by Specification 4.3.A.2.c.

   b. The control rod directional control valves for inoperable control rods shall be disarmed electrically.

4.3 REACTIVITY CONTROL

Applicability:

Applies to the surveillance requirements of the control rod system.

Objective:

To verify the ability of the control rod system to control reactivity.

Specification:

A. Reactivity Limitations

1. Reactivity margin - core loading

   Sufficient control rods shall be withdrawn following a refueling outage when core alterations were performed to demonstrate with a margin of 0.38% $\Delta k/k$ the core can be made subcritical at any time in the subsequent fuel cycle with the analytically determined strongest operable control rod fully withdrawn and all other operable rods fully inserted.

2. Reactivity margin - inoperable control rods

   a. Each partially or fully withdrawn operable control rod shall be exercised one notch at least once each week when operating above 30% power. In the event power operation is continuing with three or more inoperable control rods, this test shall be performed at least once each day, when operating above 30% power.

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 an attempt to fully insert the control rod shall be made. If the control rod cannot be fully inserted, 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, full 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:

.B Control Rods

control rod directional control valves disarmed electrically. This requirement does not apply in the refuel condition when the reactor is vented. Two control rod drives may be removed as long as Specification 3.3.A.1 is met.

2. The control rod drive housing support system shall be in place during reactor power operation or when the reactor coolant system is pressurized above atmospheric pressure with fuel in the reactor vessel, unless all control rods are fully inserted and Specification 3.3.A.1 is met.

3. a. Whenever the reactor is in the startup or run modes below 20% rated power the Rod Sequence Control System (RSCS) shall be operable.

Note: The Rod Sequence Control System (RSCS) has been evaluated only through the first refueling outage. A complete re-evaluation is required prior to operations following the first refueling outage.

4.3.B Control Rods

a. Verify that the control rod is following the drive by observing a response in the nuclear instrumentation each time a rod is moved when the reactor is operating above the pre-set power level of the RSCS.

b. When the rod is fully withdrawn the first time after each refueling outage or after maintenance, observe that the drive does not go to the overtravel position.

2. The control rod drive housing support system shall be inspected after reassembly and the results of the inspection recorded.

3. Prior to the start of control rod withdrawal at startup, and prior to attaining 20% rated power during rod insertion at shutdown, the capability of the Rod Sequence Control System (RSCS) an the Rod Worth Minimizer to properly fulfill their functions shall be verified by the following checks:

3.3.B Control Rods

b. During the shutdown procedure no rod movement is permitted between the testing performed above 20% power and the reinstatement of the RSCS restraints at or above 20% power. Alignment of rod groups shall be accomplished prior to performing the tests.

c. Whenever the reactor is in the startup or run modes below 20% rated power the Rod Worth Minimizer shall be operable or a second licensed operator shall verify that the operator at the reactor console is following the control rod program.

d. If Specifications 3.3.B.3.a through .c cannot be met the reactor shall not be started, or if the reactor is in the run or startup modes at less than 20% rated power, it shall be brought to a shutdown condition immediately.

4.3.B Control Rods

a. The capability of the RSCS to properly fulfill its function shall be verified by the following tests:

Sequence portion - Select a sequence and attempt to withdraw a rod in the remaining sequences. Move one rod in a sequence and select the remaining sequences and attempt to move a rod in each. Repeat for all sequences.

Group notch portion - For each of the six comparator circuits go through test initiate; comparator inhibit; verify; reset. On seventh attempt test is allowed to continue until completion is indicated by illumination of test complete light.

b. The capability of the Rod Worth Minimizer (RWM) shall be verified by the following checks:

1. The correctness of the control rod withdrawal sequence input to the RWM computer shall be verified before reactor startup or shutdown.

2. The RWM computer on line diagnostic test shall be successfully performed.

3. Prior to startup, proper annunciation of the selection error of at least one out-of-sequence control rod shall be verified.

4. Prior to startup, the rod block function of the RWM shall be verified by moving an out-of-sequence control rod.

5. Prior to obtaining 20% rated power during rod insertion at shutdown, verify the latching of the proper rod group and proper annunciation after insert errors.

3.3.B Control Rods

4. Control rods shall not be withdrawn for startup or refueling unless at least two source range channels have an observed count rate equal to or greater than three counts per second.

5. During operation with limiting control rod patterns, as determined by the designated qualified personnel, either:

   a. Both RBM channels shall be operable:
   or

   b. Control rod withdrawal shall be blocked.

4.3.B Control Rods

   c. When required, the presence of a second licensed operator to verify the following of the correct rod program shall be verified.

4. Prior to control rod withdrawal for startup or during refueling, verify that at least two source range channels have an observed count rate of at least three counts per second.

5. When a limiting control rod pattern exists, an instrument functional test of the RBM shall be performed prior to withdrawal of the designated rod(s) and at least once per 24 hours thereafter.

C. Scram Insertion Times

1. The average scram insertion time, based on the deenergization of the scram pilot valve solenoids as time zero, of all operable control rods in the reactor power operation condition shall be no greater than:

% Inserted From Fully Withdrawn	Avg. Scram Insertion Times (sec)
5	0.375
20	0.90
50	2.0
90	5.0

C. Scram Insertion Times

1. After each refueling outage all operable rods shall be scram time tested from the fully withdrawn position with the nuclear system pressure above 950 psig (with saturation temperature). This testing shall be completed prior to exceeding 40% power. Below 20% power, only rods in those sequences (A_{12} and A_{34} or B_{12} and B_{34}) which were fully withdrawn in the region from 100% rod density to 50% rod density shall be scram time tested. During all scram time testing below 20% power the RWM shall be operable.

3.3.C Scram Insertion Times

2. The average of the scram insertion times for the three fastest operable control rods of all groups of four control rods in a two-by-two array shall be no greater than:

% Inserted From Fully Withdrawn	Avg. Scram Insertion Times (sec)
5	0.398
20	0.954
50	2.120
90	5.300

3. The maximum scram insertion time for 90% insertion of any operable control rod shall not exceed 7.00 seconds.

4.3.C Scram Insertion Times

2. At 16-week intervals, 10% of the operable control rod drives shall be scram timed above 800 psig. Whenever such scram time measurements are made, an evaluation shall be made to provide reasonable assurance that proper control rod drive performance is being maintained.

D. Reactivity Anomalies

The reactivity equivalent of the difference between the actual critical rod configuration and the expected configuration during power operation shall not exceed 1% Δk. If this limit is exceeded, the reactor will be shut down until the cause has been determined and corrective actions have been taken as appropriate.

D. Reactivity Anomalies

During the startup test program and startup following refueling outages, the critical rod configurations will be compared to the expected configurations at selected operating conditions. These comparisons will be used as base data for reactivity monitoring during subsequent power operation throughout the fuel cycle. At specific power operating conditions, the critical rod configuration will be compared to the configuration expected based upon appropriately corrected past data. This comparison will be made at least every full power month.

3.3 Reactivity Control

E. If Specifications 3.3.C and .D above cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the shutdown condition within 24 hours.

4.3 Reactivity Control

A. Reactivity Limitation

1. The requirements for the control rod drive system have been identified by evaluating the need for reactivity control via control rod movement over the full spectrum of plant conditions and events. As discussed in subsection 3.4 of the Final Safety Analysis Report, the control rod system design is intended to provide sufficient control of core reactivity that the core could be made subcritical with the strongest rod fully withdrawn. This reactivity characteristic has been a basic assumption in the analysis of plant performance. Compliance with this requirement can be demonstrated conveniently only at the time of initial fuel loading or refueling. Therefore, the demonstration must be such that it will apply to the entire subsequent fuel cycle. The demonstration shall be performed with the reactor core in the cold, xenon-free condition and will show that the reactor is subcritical by at least R + 0.38% Δk with the analytically determined strongest control rod fully withdrawn.

   The value of "R", in units of %Δk, is the amount by which the core reactivity, in the most reactive condition at any time in the subsequent operating cycle, is calculated to be greater than at the time of the demonstration. "R", therefore, is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated beginning-of-life core reactivity. The value of "R" must be positive or zero and must be determined for each fuel cycle.

   The demonstration is performed with a control rod which is calculated to be the strongest rod. In determining this "analytically strongest" rod, it is assumed that every fuel assembly of the same type has identical material properties. In the actual core, however, the control cell material properties vary within allowed manufacturing tolerances, and the strongest rod is determined by a combination of the control cell geometry and local k_∞. Therefore, an additonal margin is included in the shutdown margin test to account for the fact that the rod used for the demonstation (the "analytically strongest") is not necessarily the strongest rod in the core. Studies have been made which compare experimental criticals with calculated criticals. These studies have shown that actual criticals can be predicted within a given tolerance band. For gadolinia cores the additional margin required due to control cell material manufacturing tolerances and calculational uncertainties has experimentally been determined to be 0.38% Δk. When this additional margin is demonstrated, it assures that the reactivity control requirement is met.

2. Reactivity margin - inoperable control rods - Specification 3.3.A.2 requires that a rod be taken out of service if it cannot be moved with drive pressure. If the rod is fully

inserted and disarmed electrically*, it is in a safe position of maximum contribution to shutdown reactivity. If it is disarmed electrically in a non-fully inserted position, that position shall be consistent with the shutdown reactivity limitations stated in Specification 3.3.A.1. This assures that the core can be shut down at all times with the remaining control rods assuming the strongest operable control rod does not insert. Also if damage within the control rod drive mechanism and in particular, cracks in drive internal housings, cannot be ruled out, then a generic problem affecting a number of drives cannot be ruled out. Circumferential cracks resulting from stress assisted intergranular corrosion have occurred in the collet housing of drives at several BWRs. This type of cracking could occur in a number of drives and if the cracks propagated until severance of the collet housing occurred, scram could be prevented in the affected rods. Limiting the period of operation with a potentially severed rod after detecting one stuck rod will assure that the reactor will not be operated with a large number of rods with failed collet housings. The Rod Sequence Control System is not automatically bypassed until reactor power is above 20% power. Therefore, control rod movement is restricted and the single notch exercise surveillance test is only performed above this power level. The Rod Sequence Control System prevents movement of out-of-sequence rods unless power is above 20%.

B. Control Rods

1. Control rod dropout accidents as discussed in the FSAR can lead to significant core damage. If coupling integrity is maintained, the possibility of a rod dropout accident is eliminated. The overtravel position feature provides a positive check as only uncoupled drives may reach this position. Neutron instrumentation response to rod movement provides a verification that the rod is following its drive. Absence of such response to drive movement could indicate an uncoupled condition. Rod position indication is required for proper function of the rod sequence control system and the rod worth minimizer.

2. The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the extremely remote event of a housing failure. The amount of reactivity which could be added by this small amount of rod withdrawal, which is less than a normal single withdrawal increment, will not contribute to any damage to the primary coolant system. The design basis is given in subsection 3.5.2 of the FSAR and the safety evaluation is given in subsection 3.5.4. This support is not required if the reactor coolant system is at atmospheric pressure since there would then be no driving force to rapidly eject a drive housing. Additionally, the support is not required if all control rods are fully inserted and if an adequate shutdown margin with one control rod withdrawn has been demonstrated, since the reactor would remain subcritical even in the event of complete ejection of the strongest control rod.

* To disarm the drive electrically, four amphenol type plug connectors are removed from the drive insert and withdrawal solenoids rendering the rod incapable of withdrawal. This procedure is equivalent to valving out the drive and is preferred because, in this condition, drive water cools and minimizes crud accumulation in the drive. Electrical disarming does not eliminate position indication.

3. The Rod Worth Minimizer (RWM) and the Rod Sequence Control System (RSCS) restrict withdrawals and insertions of control rods to pre-specified sequences. All patterns associated with these sequences have the characteristic that, assuming the worst single deviation from the sequence, the drop of any control rod from the fully inserted position to the position of the control rod drive would not cause the reactor to sustain a power excursion resulting in any pellet average enthalpy in excess of 280 calories per gram. An enthalpy of 280 calories per gram is well below the level at which rapid fuel dispersal could occur (i.e., 425 calories per gram). Primary system damage in this accident is not possible unless a significant amount of fuel is rapidly dispersed. Ref. Sections 3.6.6, 7.7.A, 7.16.5.3, and 14.6.2 of the FSAR and NEDO-10527 and supplements thereto.

In performing the function described above, the RWM and RSCS are not required to impose any restrictions at core power levels in excess of 20 percent of rated. Material in the cited reference shows that it is impossible to reach 280 calories per gram in the event of a control rod drop occurring at power greater than 20 percent, regardless of the rod pattern. This is true for all normal and abnormal patterns including those which maximize individual control rod worth.

At power levels below 20 percent of rated, abnormal control rod patterns could produce rod worths high enough to be of concern relative to the 280 calorie per gram rod drop limit. In this range the RWM and the RSCS constrain the control rod sequences and patterns to those which involve only acceptable rod worths.

The Rod Worth Minimizer and the Rod Sequence Control System provide automatic supervision to assure that out of sequence control rods will not be withdrawn or inserted; i.e., it limits operator deviations from planned withdrawal sequences. Ref. Section 7.16.5.3 of the FSAR. They serve as a backup to procedure control of control rod sequences, which limit the maximum reactivity worth of control rods. In the event that the Rod Worth Minimizer is out of service, when required, a second licensed operator can manually fulfill the control rod pattern conformance functions of this system. In this case, the RSCS is back up by independent procedural controls to assure conformance.

The functions of the RWM and RSCS make it unnecessary to specify a license limit on rod worth to preclude unacceptable consequences in the event of a control rod drop. At low powers, below 20 percent, these devices force adherence to acceptable rod patterns. Above 20 percent of rated power, no constraint on rod pattern is required to assure that rod drop accident consequences are acceptable. Control rod pattern constraints above 20 percent of rated power are imposed by power distribution requirements, as defined in Sections 3.5.I, 3.5.J, 4.5.I, and 4.5.J of these technical specifications. Power level for automatic bypass of the RSCS function is sensed by first stage turbine pressure.

4. The Source Range Monitor (SRM) system performs no automatic safety system function; i.e., it has no scram function. It

does provide the operator with a visual indication of neutron level. The consequences of reactivity accidents are functions of the initial neutron flux. The requirement of at least 3 counts per second assures that any transient, should it occur, begins at or above the initial value of 10^{-9} of rated power used in the analyses of transients from cold conditions. One operable SRM channel would be adequate to monitor the approach to criticality using homogeneous patterns of scattered control rod withdrawal. A minimum of two operable SRM's are provided as an added conservatism.

5. The Rod Block Monitor (RBM) is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density during high power level operation. Two channels are provided, and one of these may be bypassed from the console for maintenance and/or testing. Tripping of one of the channels will block erroneous rod withdrawal soon enough to prevent fuel damage. The specified restrictions with one channel out of service conservatively assure that fuel damage will not occur due to rod withdrawal errors when this condition exists.

   A limiting control rod pattern is a pattern which results in the core being on a thermal hydraulic limit (i.e., MCPR - 1.25 or LHGR = 18.5). During use of such patterns, it is judged that testing of the RBM system prior to withdrawal of such rods to assure its operability will assure that improper withdrawal does not occur. It is normally the responsibility of the Nuclear Engineer to identify these limiting patterns and the designated rods either when the patterns are initially established or as they develop due to the occurrence of inoperable control rods in other than limiting patterns. Other personnel qualified to perform these functions may be designated by the plant superintendent to perform these functions.

C. Scram Insertion Times

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent fuel damage; i.e., to prevent the MCPR from becoming less than 1.05. The limiting power transient is that resulting from the inadvertent operation of the HPCI system. Analysis of this transient shows that the negative reactivity rates resulting from the scram (FSAR Figure 3.6.15) with the average response of all the drives as given in the above specification, provide the required protection, and MCPR remains greater than 1.05.

On an early BWR, some degradation of control rod scram performance occurred during plant startup and was determined to be caused by

particulate material (probably construction debris) plugging an internal control rod drive filter. The design of the present control rod drive (Model 7RDB144B) is grossly improved by the relocation of the filter to a location out of the scram drive path: i.e., it can no longer interfere with scram performance, even if completely blocked.

The degraded performance of the original drive (CRD7RDB144A) under dirty operating conditions and the insensitivity of the redesigned drive (CRD7RDB144B) has been demonstrated by a series of engineering tests under simulated reactor operating conditions. The successful performance of the new drive under actual operating conditions has also been demonstrated by consistently good in-service test results for plants using the new drive and may be inferred from plants using the older model drive with a modified (larger screen size) internal filter which is less prone to plugging. Data has been documented by surveillance reports in various operating plants. These include Oyster Creek, Monticello, Dresden 2 and Dresden 3. Approximately 5000 drive tests have been recorded to date.

Following identification of the "plugged filter" problem, very frequent scram tests were necessary to ensure proper performance. However, the more frequent scram tests are now considered totally unnecessary and unwise for the following reasons:

1. Erratic scram performance has been identified as due to an obstructed drive filter in type "A" drives. The drives in BFNP are of the new "B" type design whose scram performance is unaffected by filter condition.

2. The dirt load is primarily released during startup of the reactor when the reactor and its systems are first subjected to flows and pressure and thermal stresses. Special attention and measures are now being taken to assure cleaner systems. Reactors with drives identical or similar (shorter stroke, smaller piston areas) have operated through many refueling cycles with no sudden or erratic changes in scram performance. This preoperational and startup testing is sufficient to detect anomalous drive performance.

3. The 72-hour outage limit which initiated the start of the frequent scram testing is arbitrary, having no logical basis other than quantifying a "major outage" which might reasonably be caused by an event so severe as to possibly affect drive performance. This requirement is unwise because it provides an incentive for shortcut actions to hasten returning "on line" to avoid the additional testing due a 72-hour outage.

The surveillance requirement for scram testing of all the control rods after each refueling outage and 10% of the control rods at 16-week intervals is adequate for determining the operability of the control rod system yet is not so frequent as to cause excessive wear on the control rod system components.

The numerical values assigned to the predicted scram performance are based on the analysis of data from other BWR's with control rod drives the same as those on Browns Ferry Nuclear Plant.

The occurrence of scram times within the limits, but significantly longer than the average, should be viewed as an indication of systematic problem with control rod drives especially if the number of drives exhibiting such scram times exceeds eight, the allowable number of inoperable rods.

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.

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.

3.4 STANDBY LIQUID CONTROL SYSTEM

Applicability

Applies to the operating status of the Standby Liquid Control System.

Objective

To assure the availability of a system with the capability to shut down the reactor and maintain the shutdown condition without the use of control rods.

Specification

A. Normal System Availability

1. The standby liquid control system shall be operable at all times when there is fuel in the reactor vessel and the reactor is not in a shutdown condition with all operable control rods fully inserted except as specified in 3.4.B.1.

4.4 STANDBY LIQUID CONTROL SYSTEM

Applicability

Applies to the surveillance requirements of the Standby Liquid Control System.

Objective

To verify the operability of the Standby Liquid Control System.

Specification

A. Normal System Availability

The operability of the Standby Liquid Control System shall be verified by the performance of the following tests:

1. At least once per month each pump loop shall be functionally tested.

2. At least once during each operating cycle:

   a. Check that the setting of the system relief valves is 1425 ± 75 psig.

   b. Manually initiate the system, except explosive valves. Pump boron solution through the recirculation path and back to the Standby Liquid Control Solution Tank. Minimum pump flow rate of 39 gpm

3.4 STANDBY LIQUID CONTROL SYSTEM

B. Operation with Inoperable Components:

1. From and after the date that a redundant component is made or found to be inoperable, Specification 3.4.A.1 shall be considered fulfilled and continued operation permitted provided that the component is returned to an operable condition within seven days.

4.4 STANDBY LIQUID CONTROL SYSTEM

against a system head of 1275 psig shall be verified. After pumping boron solution, the system shall be flushed with demineralized water.

c. Manually initiate one of the Standby Liquid Control System loops and pump demineralized water into the reactor vessel.

This test check explosion of the charge associated with the tested loop, proper operation of the valves, and pump operability. Replacement charges shall be selected such that the age of charge in service shall not exceed five years from the manufacturers assembly date.

d. Both systems, including both explosive valves, shall be tested in the course of two operating cycles.

B. Surveillance with Inoperable Components:

1. When a component is found to be inoperable, its redundant component shall be demonstrated to be operable immediately and daily thereafter until the inoperable component is repaired.

3.4 STANDBY LIQUID CONTROL SYSTEM

C. Sodium Pentaborate Solution

At all times when the Standby Liquid Control System is required to be operable the following conditions shall be met:

1. The net volume - concentration of the Liquid Control Solution in the liquid control tank shall be maintained as required in Figure 3.4.1.

2. The temperature of the liquid control solution shall be maintained above the curve shown in Figure 3.4.2. This includes the piping between the standby liquid control tank and the suction inlet to the pumps.

D. If specification 3.4.A through C cannot be met, the reactor shall be placed in a Shutdown Condition with all operable control rods fully inserted within 24 hours.

4.4 STANDBY LIQUID CONTROL SYSTEM

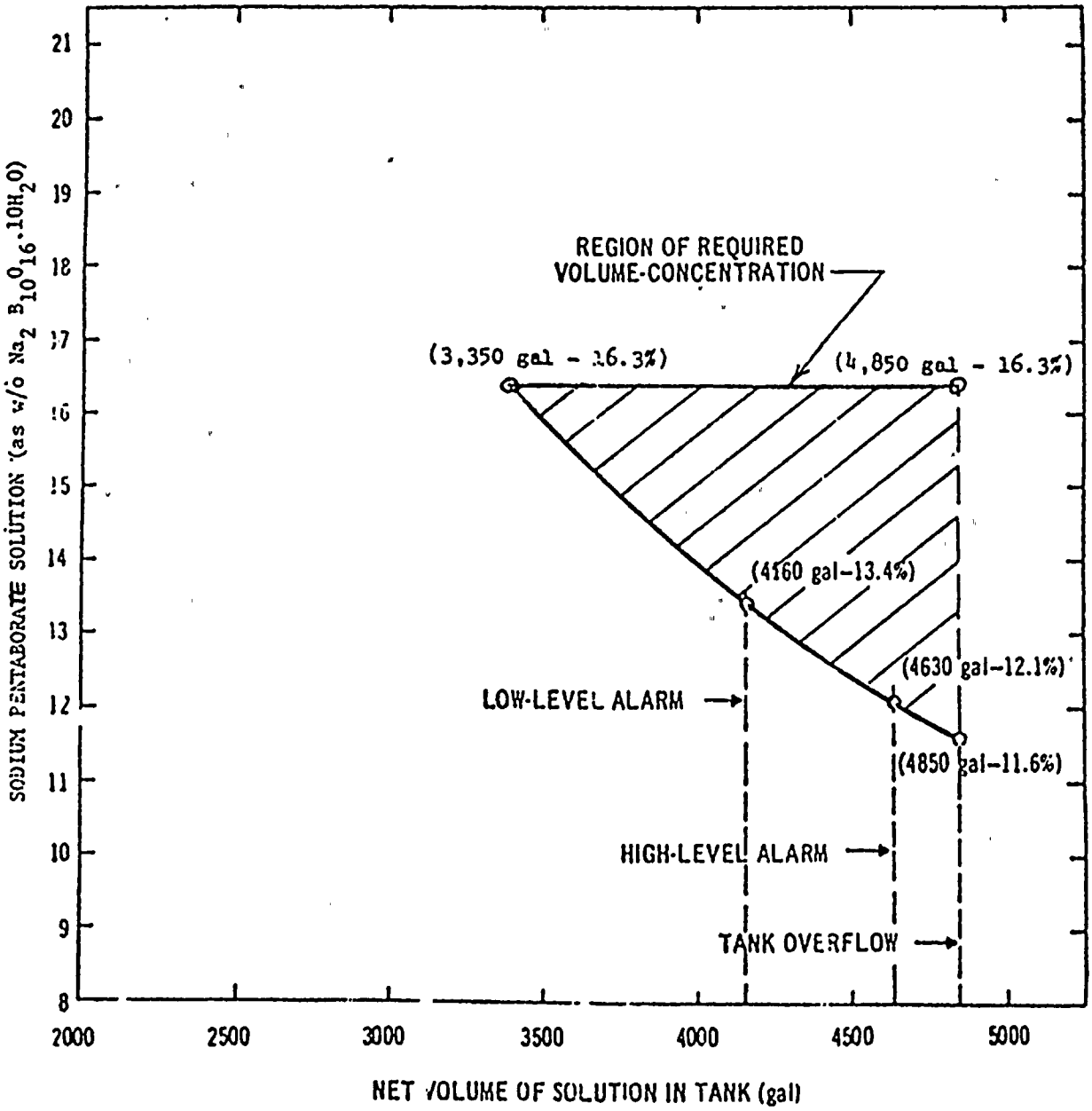
C. Sodium Pentaborate Solution

The following tests shall be performed to verify the availability of the Liquid Control Solution:

1. Volume: Check at least once per day.

2. Temperature: Check at least once per day.

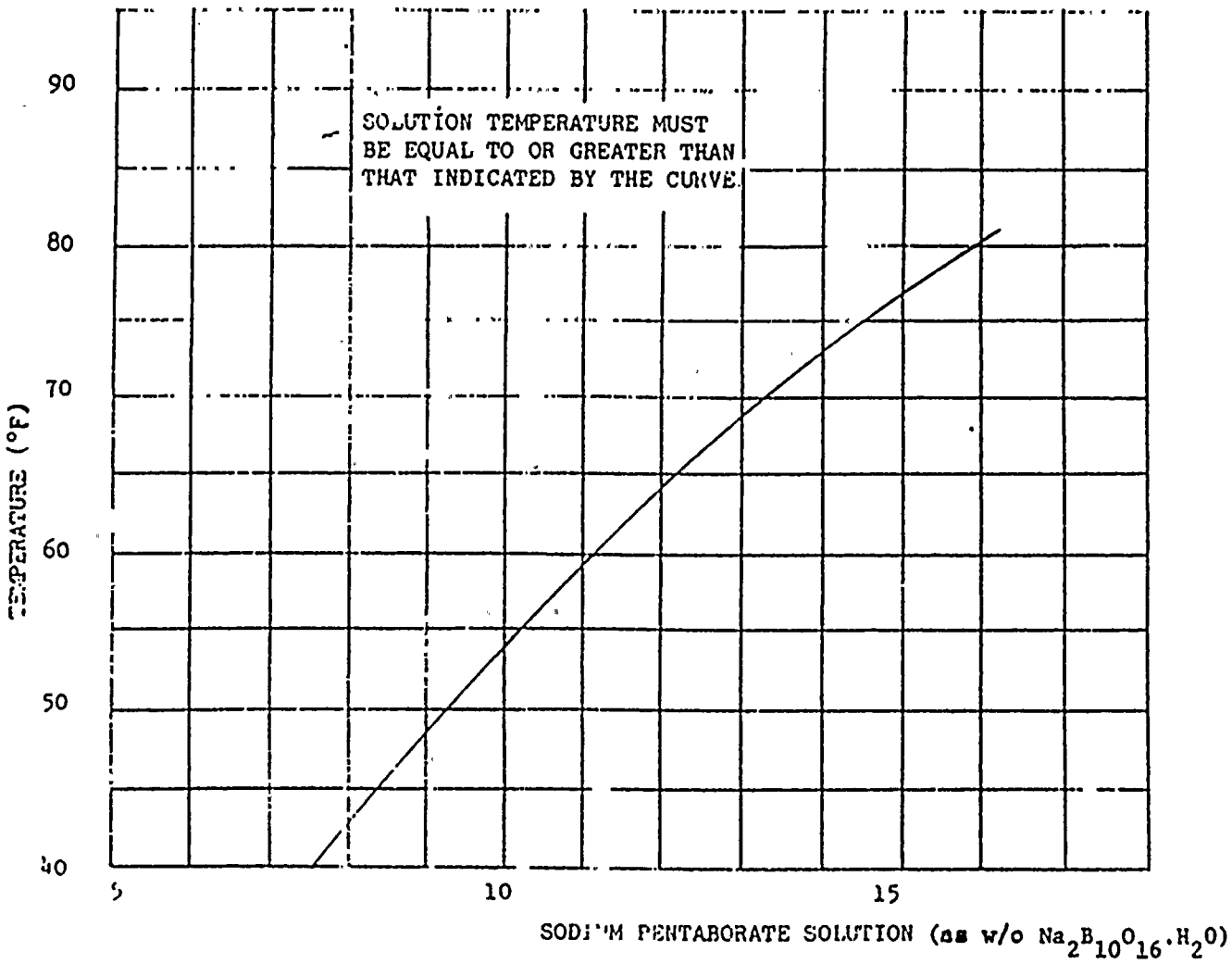
3. Concentration: Check at least once per month. Also check concentration any time water or boron is added to the solution or solution temperature is below the temperature required in Figure 3.4.2.



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

SODIUM PENTABORATE SOLUTION
VOLUME-CONCENTRATED REQUIREMENTS

FIGURE 3.4-1



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

SODIUM PENTABORATE SOLUTION
TEMPERATURE REQUIREMENTS

FIGURE 3.4-2

.4 BASES: STANDBY LIQUID CONTROL SYSTEM

A. If no more than one operable control rod is withdrawn, the basic shutdown reactivity requirement for the core is satisfied and the Standby Liquid Control System is not required. Thus, the basic reactivity requirement for the core is the primary determinant of when the liquid control system is required.

The purpose of the liquid control system is to provide the capability of bringing the reactor from full power to a cold, xenon-free shutdown condition assuming that none of the withdrawn control rods can be inserted. To meet this objective, the liquid control system is designed to inject a quantity of boron that produces a concentration greater than 600 ppm of boron in the reactor core in less than 125 minutes. The 600 ppm concentration in the reactor core is required to bring the reactor from full power to a five percent Δk subcritical condition, considering the hot to cold reactivity difference, xenon poisoning, etc. The time requirement for inserting the boron solution was selected to override the rate of reactivity insertion caused by cooldown of the reactor following the xenon poison peak.

T e minimum limitation on the relief valve setting is intended to prevent the loss of liquid control solution via the lifting of a relief valve at too low a pressure. The upper limit on the relief valve settings provides system protection from overpressure.

B. Only one of the two standby liquid control pumping loops is needed for operating the system. One inoperable pumping circuit does not immediately threaten shutdown capability, and reactor operation can continue while the circuit is being repaired. Assurance that the remaining system will perform its intended function and that the long-term average availability of the system is not reduced is obtained fro a one-out-of-two system by an allowable equipment out-of-service time of one-third of the normal surveillance frequency. This method determines an equipment out-of-service time of ten days. Additional conservatism is introduced by reducing the allowable out-of-service time to seven days, and by increased testing of the operable redundant component.

C. Level indication and alarm indicate whether the solution volume has changed, which might indicate a possible solution concentration change. The test interval has been established in consideration of these factors. Temperature and liquid level alarms for the system are annunciated in the control room.

The solution is kept at least 10°F above the saturation temperature to guard against boron precipitation. The margin is included in Figure 3.4.2.

The volume concentration requirement of the solution are such that should evaporation occur from any point within the curve, a low level alarm will annunciate before the temperature-concentration requirements are exceeded.

BASES:

The quantity of stored boron includes an additional margin (25 percent) beyond the amount needed to shut down the reactor to allow for possible imperfect mixing of the chemical solution in the reactor water.

A minimum quantity of 4,160 gallons of solution having a 13.4 percent sodium pentaborate concentration or the equivalent is required to meet this shutdown requirement as defined in Figure 3.4.1.

4.4 BASES: STANDBY LIQUID CONTROL SYSTEM

Experience with pump operability indicates that the monthly test, in combination with the tests during each operating cycle, is sufficient to maintain pump performance. Various components of the system are individually tested periodically, thus making unnecessary more frequent testing of the entire system.

The solution temperature and volume are checked at a frequency to assure a high reliability of operation of the system should it ever be required.

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

Applicability

Applies to the operational status of the core and containment cooling systems.

Objective

To assure the operability of the core and containment cooling systems under all conditions for which this cooling capability is an essential response to plant abnormalities.

Specification

A. Core Spray System (CSS)

1. The CSS shall be operable:

   (1) prior to reactor startup from a cold condition, or

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

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

Applicability

Applies to the surveillance requirements of the core and containment cooling systems when the corresponding limiting condition for operation is in effect.

Objective

To verify the operability of the core and containment cooling systems under all conditions for which this cooling capability is an essential response to plant abnormalities.

Specification

A. Core Spray System (CSS)

1. Core Spray System Testing.

	Item	Frequency
a.	Simulated Automatic Actuation test	Once/ Operating Cycle
b.	Pump Operability	Once/ month
c.	Motor Operated Valve Operability	Once/ month
d.	System flow rate: Each loop shall deliver at least 6250 gpm against a system head corresponding to a	Once/3 months

3.5.A Core Spray System (CSS)

2. If one CSS loop is inoperable, the reactor may remain in operation for a period not to exceed 7 days providing all active components in the other CSS loop and the RHR system (LPCI mode) and the diesel generators are operable.

3. If specification 3.5.A.1 or specification 3.5.A.2 cannot be met, the reactor shall be shutdown in the Cold Condition within 24 hours.

4. When the reactor vessel pressure is atmospheric and irradiated fuel is in the reactor vessel at least one core spray loop with one operable pump and associated diesel generator shall be operable, except with the reactor vessel head removed as specified in 3.5.A.5 or prior to reactor startup as specified in 3.5.A.1.

5. When irradiated fuel is in the reactor vessel and the reactor vessel head is removed, core spray is not required provided work is not in progress which has the potential to drain the vessel, provided the fuel pool gates are open and the fuel pool is maintained above the low level alarm point, and provided one RHRSW pump and associated valves supplying the standby coolant supply are operable.

4.5.A Core Spray System (CSS)

105 psi differential pressure between the reactor vessel and the primary containment.

e. Check Valve — Once/Operating Cycle

2. When it is determined that one core spray loop is inoperable, at a time when operability is required, the other core spray loop, the RHRS (LPCI mode), and the diesel generators shall be demonstrated to be operable immediately. The operable core spray loop shall be demonstrated to be operable daily thereafter.

3.5.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 RHRS 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 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 7 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.

4.5.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. Test 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.

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. The operable RHRS pumps (LPCI mode) shall be demonstrated to be operable every 10 days thereafter until the inoperable pump is returned to normal service.

PAGE DELETED

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

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

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)

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

4. When it is determined that more than one RHR pump (LPCI mode) as allowed in 3.5.B.4 is inoperable when operability is required, the CSS, remaining RHR pumps, and the diesel generators shall be demonstrated to be operable immediately and daily thereafter until at least three RHR pumps (LPCI mode) are returned to normal service.

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 exchanger is returned to normal service.

6. When it is determined that two RHR pumps (containment cooling mode) or associated heat exchangers are 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

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

are operable.

7. If two access paths of the RHRS (containment cooling mode) for each phase of the mode (drywell sprays, suppression chamber sprays, and suppression pool cooling) are not operable, the unit may remain in operation for a period not to exceed 7 days provided at least one path or each phase of the mode remains operable.

8. If specifications 3.5.B.1 through 3.5.B.7 are not met, an orderly shutdown shall be initiated and the reactor shall be shutdown and placed in the cold condition within 24 hours.

9. When the reactor vessel pressure is atmospheric and irradiated fuel is in the reactor vessel at least one RHR loop with two pumps or two loops with one pump per loop shall be operable. The pumps' associated diesel generators must also be operable.

10. If the conditions of specification 3.5.A.5 are met, LPCI and containment cooling are not required.

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

mode) shall be demonstrated to be operable immediately and daily thereafter until at least three RHR pumps (containment cooling mode) and associated heat exchangers are returned to normal service.

7. When it is determined that one or more access paths of the RHRS (containment cooling mode) are inoperable when access is required, all active components in the access paths of the RHRS (containment cooling mode) shall be demonstrated to be operable immediately and all active components in the access paths which are not backed by a second operable access path for the same phase of the mode (drywell sprays, suppression chamber sprays and suppression pool cooling) shall be demonstrated to be operable daily thereafter until the second path is returned to normal service.

8. No additional surveillance required.

9. When the reactor vessel pressure is atmospheric, the RHR pumps and valves that are required to be operable shall be demonstrated to be operable monthly.

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

11. When there is irradiated fuel in the reactor and the reactor vessel pressure is greater than atmospheric, 2 RHR pumps and associated heat exchangers and valves on an adjacent unit must be operable and capable of supplying cross-connect capability except as specified in specification 3.5.B.12 below. (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 the adjacent unit 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.

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

10. The RHR pumps on the adjacent units which supply cross-connect capability shall be demonstrated to be operable monthly when the cross-connect capability is required.

11. When it is determined that one RHR pump or associated heat exchanger located on the unit cross-connection in the 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 demonstrated to be operable immediately and every 15 days thereafter until the inoperable pump and associated heat exchanger are returned to normal service.

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.

14. All recirculation pump discharge valves shall be operable prior to reactor startup (or closed if permitted elsewhere in these specifications).

12. All recirculation pump discharge valves shall be tested for operability during any period of reactor cold shutdown exceeding 48 hours, if operability tests have not been performed during the preceding 31 days.

3.5.C RHR Service Water and Emergency Equipment Cooling Water Systems (EECWS)

1. Prior to reactor startup from a cold condition, 9 RHRSW pumps must be operable, with 7 pumps (including pump D1 or D2) assigned to RHRSW service and 2 automatically starting pumps assigned to EECW service.

4.5.C RHR Service Water and Emergency Equipment Cooling Water Systems (EECWS)

1. a. Each of the RHRSW pumps normally assigned to automatic service on the EECW headers will be tested automatically each time the diesel generators are tested. Each of the RHRSW pumps and all associated essential control valves for the EECW headers and RHR heat exchanger headers shall be demonstrated to be operable once every three months.

   b. Annually each RHRSW pump shall be flow-rate tested. To be considered operable, each pump shall pump at least 4500 gpm through its normally assigned flow path.

3.5.C RHR Service Water and Emergency Equipment Cooling Water Systems (EECWS) (Continued)

2. During power operation, RHRSW pumps must be operable and assigned to service as indicated below for the specified time limits.

TIME LIMIT (DAYS)	MINIMUM SERVICE ASSIGNMENT RHRSW	EECW**
Indefinite	7*	3*
30	7* or 6***	2* or 3***
7	6*	2*

*At least one operable pump must be assigned to each header.

**Only automatically starting pumps may be assigned to EECW header service.

***Nine pumps must be operable. Either configuration is acceptable: 7 and 2 or 6 and 3.

3. During power operation both RHRSW pumps D1 and D2 normally or alternately assigned to the RHR heat exchanger header supplying the standby coolant supply connection must be operable except as specified in 3.5.C.4.a below.

4.5.C RHR Service Water and Emergency Equipment Cooling Water Systems (EECWS) (Continued)

2. a. If no more than two RHRSW pumps are inoperable, increased surveillance is not required.

b. When three RHRSW pumps are inoperable, the remaining pumps, associated essential control valves, and associated diesel generators shall be operated weekly.

c. When four RHRSW pumps are inoperable, the remaining pumps, associated essential control valves, and associated diesel generators shall be operated daily.

3. Routine surveillance for these pumps is specified in 4.5.C.1.

3.5.C (Continued)

4. One of the D1 or D2 RHRSW pumps may be inoperable for a period not to exceed 30 days provided the operable pump is aligned to supply the RHR heat exchanger and the associated diesel generator and the essential control valves are operable..

5. If Specification 3.5.C.2 through 3.5.C.4 are not met, an orderly shutdown of the unit 1 shall be initiated and the unit placed in cold shutdown condition within 24 hours.

4.5.C (Continued)

4. When it is determined that one of the RHRSW pumps supplying standby coolant is inoperable at a time when operability is required, the operable RHRSW pump on the same header and its associated diesel generator and the RHR heat exchanger header and associated essential control valves shall be demonstrated to be operable immediately and every 15 days thereafter.

3.5.D Equipment Area Coolers

1. The equipment area cooler associated with each RHR pump and the equipment area cooler associated with each set of core spray pumps (A and C or B and D) must be operable at all times when the pump or pumps served by that specific cooler is considered to be operable.

2. When an equipment area cooler is not operable, the pump(s) served by that cooler must be considered inoperable for Technical Specification purposes.

4.5.D Equipment Area Coolers

1. Each equipment area coolers is operated in conjunction with the equipment served by that particular cooler; therefore, the equipment area coolers are tested at the same frequency as the pumps which they serve.

E. High Pressure Coolant Injection System (HPCIS)

1. The HPCI system shall be operable:

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

   (2) whenever there is irradiated fuel in the reactor vessel and the reactor vessel pressure is greater than 122 psig, except as specified in specification 3.5.E.2.

E. High Pressure Coolant Injection System (HPCIS)

1. HPCI Subsystem testing shall be performed as follows:

a.	Simulated Automatic Actuation Test	Once/ operating cycle
b.	Pump Operability	Once/ month
c.	Motor Operated Valve Operability	Once/ month
d.	Flow Rate at normal reactor vessel operating pressure	Once/3 months
e.	Flow Rate at 150 psig	Once/ operating cycle

The HPCI pump shall deliver at least 5000 gpm during each flow rate test.

This page intentionally blank

3.5.E High Pressure Coolant Injection System (HPCIS)

2. If the HPCI system is inoperable, the reactor may remain in operation for a period not to exceed 7 days, provided the ADS, CSS, RHRS (LPCI), and RCICS are operable.

3. If specifications 3.5.E.1 or 3.5.E.2 are not met, an orderly shutdown shall be initiated and the reactor vessel pressure shall be reduced to 122 psig or less within 24 hours.

4.5.E High Pressure Coolant Injection System (HPCIS)

2. When it is determined that the HPCIS is inoperable the ADS actuation logic, the RCICS, the RHRS (LPCI), and the CSS shall be demonstrated to be operable immediately: The RCICS and ADS logic shall be demonstrated to be operable daily thereafter.

F. Reactor Core Isolation Cooling System (RCICS)

1. The RCICS shall be operable:

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

(2) whenever there is irradiated fuel in the reactor vessel and the reactor vessel pressure is above 122 psig, except as specified in 3.5.F.2.

F. Reactor Core Isolation Cooling System (RCICS)

1. RCIC Subsystem testing shall be performed as follows:

a.	Simulated Automatic Actuation Test	Once/operating cycle
b.	Pump Operability	Once/month
c.	Motor Operated Valve Operability	Once/month
d.	Flow Rate at normal reactor vessel operating pressure	Once/3 months
e.	Flow Rate at 150 psig	Once/operating cycle

The RCIC pump shall deliver at least 600 gpm during each flow test.

3.5.F Reactor Core Isolation Cooling

2. If the RCICS is inoperable, the reactor may remain in operation for a period not to exceed 7 days if the HPCIS is operable during such time.

3. If specifications 3.5.F.1 or 3.5.F.2 are not met, an orderly shutdown shall be initiated and the reactor shall be depressurized to less than 122 psig within 24 hours.

4.5.F Reactor Core Isolation Cooling

2. When it is determined that the RCICS is inoperable, the HPCIS shall be demonstrated to be operable immediately and weekly thereafter.

G. Automatic Depressurization System (ADS)

1. Five of the six valves of the Automatic Depressurization System shall be operable:

   (1) prior to a Startup from a Cold Condition, or,

   (2) whenever there is irradiated fuel in the reactor vessel and the reactor vessel pressure is greater than 105 psig, except as specified in 3.5.G.2 and 3.5.G.3 below.

2. If more than one ADS valve is known to be incapable of automatic operation, the reactor may remain in operation for a period not to exceed 7 days, provided the HPCI system is operable. (Note that the pressure relief function of these valves is assured by section 3.6.D of these specifications and that this specification only applies to the ADS function.)

G. Automatic Depressurization System (ADS)

1. During each operating cycle the following tests shall be performed on the ADS:

   a. A simulated automatic actuation test shall be performed prior to startup after each refueling outage. Manual surveillance of the relief valves is covered in 4.6.D.2.

2. When it is determined that more than one of the ADS valves are incapable of automatic operation, the HPCIS shall be demonstrated to be operable immediately and daily thereafter as long as Specification 3.5.G.2 applies.

3.5.G Automatic Depressurization System (ADS)

3. If specifications 3.5.G.1 and 3.5.G.2 cannot be met, an orderly shutdown will be initiated and the reactor vessel pressure shall be reduced to 105 psig or less within 24 hours.

H. Maintenance of Filled Discharge Pipe

Whenever the core spray systems, LPCI, HPCI, or RCIC are required to be operable, the discharge piping from the pump discharge of these systems to the last block valve shall be filled.

4.5.G Automatic Depressurization System (ADS)

H. Maintenance of Filled Discharge Pipe

The following surveillance requirements shall be adhered to to assure that the discharge piping of the core spray systems, LPCI, HPCI, and RCIC are filled:

7.H Maintenance of Filled Discharge Pipe

The suction of the RCIC and HPCI pumps shall be aligned to the condensate storage tank, and the pressure suppression chamber head tank shall normally be aligned to serve the discharge piping of the RHR and CS pumps. The condensate head tank may be used to serve the RHR and CS discharge piping if the PSC head tank is unavailable. The pressure indicators on the discharge of the RHR and CS pumps shall indicate not less than listed below.

P1-75-20	48 psig
P1-75-48	48 psig
P1-74-51	48 psig
P1-74-65	48 psig

I. Average Planar Linear Heat Generation Rate

During steady state power operation, the Maximum Average Planar Heat Generation Rate (MAPLHGR) for each type of fuel as a function of average planar exposure shall not exceed the limiting value shown in Figures 3.5.1.A and 3.5.1.B. If at any time during operation it is determined by normal surveillance that the limiting value for APLHGR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the APLHGR 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.

J. Linear Heat Generation Rate (LHGR)

During steady state power operation, the linear heat generation rate (LHGR) of any rod in any fuel assembly at any axial location shall not exceed the maximum allowable LHGR as calculated by the following equation:

4.5.H Maintenance of Filled Discharge Pipe

1. Every month prior to the testing of the RHRS (LPCI and Containment Spray) and core spray systems, the discharge piping of these systems shall be vented from the high point and water flow determined.

2. Following any period where the LPCI or core spray systems have not been required to be operable, the discharge piping of the inoperable system shall be vented from the high point prior to the return of the system to service.

3. Whenever the HPCI or RCIC system is lined up to take suction from the condensate storage tank, the discharge piping of the HPCI and RCIC shall be vented from the high point of the system and water flow observed on a monthly basis.

4. When the RHRS and the CSS are required to be operable, the pressure indicators which monitor the discharge lines shall be monitored daily and the pressure recorded.

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

The MAPLHGR for each type of fuel as a function of average planar exposure shall be determined daily during reactor operation at $\geq$ 25% rated thermal power.

J. Linear Heat Generation Rate (LHGR)

The LHGR as a function of core height shall be checked daily during reactor operation at $\geq$ 25% rated thermal power.

$LHGR_{max} \leq LHGR_d[1 - (\Delta P/P)_{max} (L/LT)]$

$LHGR_d$ = Design LHGR = 18.5 kW/ft.

$(\Delta P/P)_{max}$ = Maximum power spiking penalty = 0.026

LT = Total core length = 12 feet

L = Axial position above bottom of core

If at any time during operation it is determined by normal surveillance that the limiting value for LHGR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the LHGR 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.

K. Minimum Critical Power Ratio (MCPR)

During steady state power operation, MCPR shall be $\geq$ 1.25 at rated power and flow. For core flows other than rated the MCPR shall be > 1.25 times K_f where K_f is as 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.

K. Minimum Critical Power Ratio (MCPR)

MCPR shall be determined daily during reactor power operation at $\geq$ 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 fc Specification 3.3.

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 redundancy 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 have the RHRS in service if a "pipe-break" type of accident should occur, it is permitted to be out of operation for only a restricted amount of time and when the system pressure is low. At least one-half of the containment cooling function must remain operable during this time period. Requiring two operable CSS pumps during cooldown allows for flushing the RHRS even if the shutdown were caused by inability to meet the CSS specifications (3.5.A) on a number of operable pumps.

When the reactor vessel pressure is atmospheric, the limiting conditions for operation are less restrictive. At atmospheric pressure, the minimum requirement is for one supply of makeup water to the core. Requiring two operable RHR pumps and one CSS pump provides redundancy to ensure makeup water availability.

Should one RHR pump or associated heat exchanger located on the unit cross-connection in the adjacent unit become inoperable, an equal capability for long-term fluid makeup to the reactor and for cooling of the containment remains operable. Because of the availability of an equal makeup and cooling capability, which is demonstrated to be operable immediately and with specified subsequent surveillance, a 30-day repair period is justified.

3.5 BASES

3.5.A Core Spray System (CSS) and 3.5.B Residual Heat Removal System (RHRS)

Analyses presented in the FSAR* and analyses presented in conformance with 10CFR50, Appendix K, demonstrated that the core spray system in conjunction with two LPCI pumps provides adequate cooling to the core to dissipate the energy associated with the loss-of-coolant accident and to limit fuel clad temperature to below 2,200°F which assures that core geometry remains intact and to limit the core average clad metal-water reaction to less than one percent. Core spray distribution has been shown in tests of systems similar to design to BFNP to exceed the minimum requirements. In addition, cooling effectiveness has been demonstrated at less than half the rated flow in simulated fuel assemblies with heater rods to duplicate the decay heat characteristics of irradiated fuel.

The RHRS (LPCI mode) is designed to provide emergency cooling to the core by flooding in the event of a loss-of-coolant accident. This system is completely independent of the core spray system; however, it does function in combination with the core spray system to prevent excessive fuel clad temperature. The LPCI mode of the RHRS and the core spray system provide adequate cooling for break areas of approximately 0.2 square feet up to and including the double-ended recirculation line break without assistance from the high-pressure emergency core cooling subsystems.

The intent of the CSS and RHRS specifications is to not allow startup from the cold condition without all associated equipment being operable. However, during operation, certain components may be out of service for the specified allowable repair times. The allowable repair times have been selected using engineering judgment based on experiences and supported by availability analysis. Assurance of the availability of the remaining systems is increased by demonstrating operability immediately and by requiring selected testing during the outage period.

Should one core spray loop become inoperable, the remaining core spray loop, the RHR system, and the diesel generators are demonstrated to be operable to ensure their availability should the need for core cooling arise. These provide extensive margin over the operable equipment needed for 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.

*A detailed functional analysis is given in Section 6 of the BFNP FSAR.

Bases

The suppression chamber can be drained when the reactor vessel pressure is atmospheric, irradiated fuel is in the reactor vessel, and work is not in progress which has the potential to drain the vessel. By requiring the fuel pool gate to be open with the vessel head removed, the combined water inventory in the fuel pool, the reactor cavity, and the separator/dryer pool, between the fuel pool low level alarm and the reactor vessel flange, is about 65,800 cubic feet (492,000 gallons). This will provide adequate low-pressure cooling in lieu of CSS and RHR (LPCI and containment cooling mode) as currently required in specifications 3.5.A.4 and 3.5.B.9. The additional requirements for providing standby coolant supply available will ensure a redundant supply of coolant supply. Control rod drive maintenance may continue during this period provided no more than one drive is removed at a time unless blind flanges are installed during the period of time CRD's are not in place.

Should the capability for providing flow through the cross-connect lines be lost, a ten day repair time is allowed before shutdown is required. This repair time is justified based on the very small probability for ever needing RHR pumps and heat exchangers to supply an adjacent unit.

REFERENCES

1. Residual Heat Removal System (BFNP FSAR subsection 4.8)

2. Core Standby Cooling Systems (BFNP FSAR Section 6)

3.5.C RHR Service Water System and Emergency Equipment Cooling Water System (EECWS)

There are two EECW headers (north and south) with four automatic starting RHRSW pumps on each header. All components requiring emergency cooling water are fed from both headers thus assuring continuity of operation if either header is operable. Each header alone can handle the flows to all components. Two RHRSW pumps can supply the full flow requirements of all essential EECW loads for any abnormal or postaccident situation.

There are four RHR heat exchanger headers (A, B, C, & D) with one RHR heat exchanger from each unit on each header. There are two RHRSW pumps on each header; one normally assigned to each header (A2, B2, C2, or D2) and one on alternate assignment (A1, B1, C1, or D1). One RHR heat exchanger header can adequately deliver the flow supplied by both RHRSW pumps to any two of the three RHRSW heat exchangers on the header. One RHRSW pump can supply the full flow requirement of one RHR heat exchanger. Two RHR heat exchangers can more than adequately handle the cooling requirements of one unit in any abnormal or postaccident situation.

The RHR Service Water Systems was designed as a shared system for three units. The specification, as written, is conservative when consideration is given to particular pumps being out of service and to possible valving arrangements. If unusual operating conditions arise such that more pumps are out of service than allowed by this specification, a special case request may be made to the NRC to allow continued operation if the actual system cooling requirements can be assured.

Should one of the two RHRSW pumps normally or alternately assigned to the RHR heat exchanger header supplying the standby coolant supply connection become inoperable, an equal capability for long-term fluid makeup to the unit reactor and for cooling of the unit containment remains operable. Because of the availability of an equal makeup and cooling capability which is demonstrated to be operable immediately and with specified subsequent surveillance, a 30-day repair period is justified. Unit 2 may be supplied standby coolant from either of four pumps--B1, B2, D1, or D2.

3.5.D Equipment Area Coolers

There is an equipment area cooler for each RHR pump and an equipment area cooler for each set (two pumps, either the A and C or B and D pumps) of core spray pumps. The equipment area coolers take suction near the cooling air discharge of the motor of the pump(s) served and discharge air near the cooling air suction of the motor of the pump(s) served. This ensures that cool air is supplied for cooling the pump motors.

The equipment area coolers also remove the pump, and equipment waste heat from the basement rooms housing the engineered safeguard equipment. The various conditions under which the operation of the equipment air coolers is required have been identified by evaluating the normal and abnormal operating transients and accidents over the full range of planned operations. The surveillance and testing of the equipment area coolers in each of their various modes is accomplished during the testing of the equipment served by these coolers. This testing is adequate to assure the operability of the equipment area coolers.

REFERENCES

1. Residual Heat Removal System (BFNP FSAR paragraphs 4.8.9.1 and 4.8.9.2)

2. Core Standby Cooling System (BFNP FSAR subsection 6.7)

3.5.E High Pressure Coolant Injection System (HPCIS)

The HPCIS is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCIS permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCIS continues to operate until reactor vessel pressure is below the pressure at which LPCI operation or core spray system operation maintains core cooling.

The capacity of the system is selected to provide this required core cooling. The HPCI pump is designed to pump 5000 gpm at reactor pressures between 1120 and 150 psig. Two sources of water are available. Initially, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor.

When the HPCI system begins operation, the reactor depressurizes more rapidly than would occur if HPCI was not initiated due to the condensation of steam by the cold fluid pumped into the reactor vessel by the HPCI system. As the reactor vessel pressure continues to decrease, the HPCI flow momentarily reaches equilibrium with the flow through the break. Continued depressurization caused the break flow to decrease below the HPCI flow and the liquid inventory

begins to rise. This type of response is typical of the small breaks. The core never uncovers and is continuously cooled throughout the transient so that no core damage of any kind occurs for breaks that lie within the capacity range of the HPCI.

The minimum required NPSH for HPCI is 21 feet. There is adequate elevation head between the suppression pool and the HPCI pump, such that the required NPSH is available with a suppression pool temperature up to 140°F with no containment back pressure.

The HPCIS serves as a backup to the RCICS as a source of feedwater makeup during primary system isolation conditions. The ADS serves as a backup to the HPCIS for reactor depressurization for postulated transients and accident. Both these systems are checked for operability if the HPCI is determined to be inoperable. Considering the redundant systems, an allowable repair time of 7 days was selected.

The HPCI and RCIC as well as all other Core Standby Cooling Systems must be operable when starting up from a Cold Condition. It is realized that the HPCI is not designed to operate at full capacity until reactor pressure exceeds 150 psig and the steam supply to the HPCI turbine is automatically isolated before the reactor pressure decreases below 100 psig. It is the intent of this specification to assure that when the reactor is being started up from a Cold Condition, the HPCI is not known to be inoperable.

1.5.F Reactor Core Isolation Cooling System (RCICS)

The various conditions under which the RCICS plays an essential role in providing makeup water to the reactor vessel have been identified by evaluating the various plant events over the full range of planned operations. The specifications ensure that the function for which the RCICS was designed will be available when needed. The minimum required NPSH for RCIC is 20 feet. There is adequate elevation head between the suppression pool and the RCIC pump, such that the required NPSH is available with a suppression pool temperature up to 140°F with no containment back pressure.

Because the low-pressure cooling systems (LPCI and core spray) are capable of providing all the cooling required for any plant event when nuclear system pressure is below 122 psig, the RCICS is not required below this pressure. Between 122 psig and 150 psig the RCICS need not provide its design flow, but reduced flow is required for certain events. RCICS design flow (600 gpm) is sufficient to maintain water level above the top of the active fuel for a complete loss of feedwater flow at design power (105 percent of rated).

Consideration of the availability of the RCICS reveals that the average risk associated with failure of the RCICS to cool the core when required is not increased if the RCICS is inoperable for no longer than 7 days, provided that the HPCIS is operable during this period.

REFERENCE

1. Reactor Core Isolation Cooling System (BFNP FSAR subsection 4.7)

3.5.G Automatic Depressurization System (ADS)

This specification ensures the operability of the ADS under all conditions for which the depressurization of the nuclear system is an essential response to station abnormalities.

The nuclear system pressure relief system provides automatic nuclear system depressurization for small breaks in the nuclear system so that the low-pressure coolant injection (LPCI) and the core spray subsystems can operate to protect the fuel barrier. Note that this specification applies only to the automatic feature of the pressure relief system.

Specification 3.6.D specifies the requirements for the pressure relief function of the valves. It is possible for any number of the valves assigned to the ADS to be incapable of performing their ADS functions because of instrumentation failures yet be fully capable of performing their pressure relief function.

Because the automatic depressurization system does not provide makeup to the reactor primary vessel, no credit is taken for the steam cooling of the core caused by the system actuation to provide further conservatism to the CSCS.

With one ADS valve known to be incapable of automatic operation, five valves remain operable to perform their ADS function. The ECCS loss-of-coolant accident analyses for small line breaks assumed that five of the six ADS valves were operable. Reactor operation with two ADS valves inoperable is only allowed to continue for seven days provided that the HPCI system is demonstrated to be operable.

3.5.H Maintenance of Filled Discharge Pipe

If the discharge piping of the core spray, LPCI, HPCIS, and RCICS are not filled, a water hammer can develop in this piping when the pump and/or pumps are started. To minimize damage to the discharge piping and to ensure added margin in the operation of these systems, this Technical Specification requires the discharge lines to be filled whenever the system is in an operable condition. If a discharge pipe is not filled, the pumps that supply that line must be assumed to be inoperable for Technical Specification purposes.

The core spray and RHR system discharge piping high point vent is visually checked for water flow once a month prior to 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 willreflect approximately 30 psig for a water level at the high point and 45 psig for a water level in the pressuresuppression 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.

3.5.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 10CFR50, 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 10CFR50 Appendix K limit. The limiting value for MAPLHGR is shown in Figures 3.5.1-A and 3.5.1-B.

3.5.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 generation if fuel pellet densification is postulated. The power spike penalty specified is based on the analysis presented in Section 3.2.1 of Reference 1 as modified in References 2 and 3, and assumes a linearly increasing variation in axial gaps between core bottom and top, and assures with a 95% confidence, that no more than one fuel rod exceeds the design linear heat generation rate due to power spiking. The LHGR as a function of core height shall be checked daily during reactor operation at ≥ 25% power to determine if fuel burnup, or control rod movement has caused changes in power distribution. For LHGR to be a limiting value below 25% rated thermal power, the MTPF would have to be greater than 10 which is precluded by a considerable margin when employing any permissible control rod pattern.

3.5.K. Minimum Critical Power Ratio (MCPR)

At core thermal power levels less than or equal to 25%, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience and thermal hydraulic analysis indicated that the resulting MCPR value is in excess of requirements by a considerable margin. With this low void content, any inadvertent core flow increase would only place operation in a more conservative mode relative to MCPR. The daily requirement for calculating MCPR above 25% rated thermal power is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in power or power shape (regardless of magnitude) that could place operation at a thermal limit.

3.5.L. Reporting Requirements

The LCO's associated with monitoring the fuel rod operating conditions are required to be met at all times, i.e., there is no allowable time in which the plant can knowingly exceed the limiting values for MAPLHGR, LHGR, and MCPR. It is a requirement, as stated in Specifications 3.5.I, .J, and .K. that if at any time during steady state power operation, it is determined that the limiting values for MAPLHGR, LHGR, or MCPR are exceeded action is then initiated to restore operation to within the prescribed limits. This action is initiated as soon as normal surveillance indicates that an operating limit has been reached. Each event involving steady state operation beyond a specified limit shall be logged 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 circumstances, 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.

4.5 Core and Containment Cooling Systems Surveillance Frequencies

The testing interval for the core and containment cooling systems is based on industry practice, quantitative reliability analysis, judgement and practicality. The core cooling systems have not been designed to be fully testable during operation. For example, in the case of the HPCI, automatic initiation during power operation would result in pumping cold water into the reactor vessel which is not desirable. Complete ADS testing during power operation causes an undesirable loss-of-coolant inventory. To increase the availability of the core and containment cooling system, the components which make up the system; i.e., instrumentation, pumps, valves, etc., are tested frequently. The pumps and motor operated injection valves are also tested each month to assure their operability. A simulated automatic actuation test once each cycle combined with monthly tests of the pumps and injection valves is deemed to be adequate testing of these systems.

When components and subsystems are out-of-service, overall core and containment cooling reliability is maintained by demonstrating the operability of the remaining equipment. The degree of operability to be demonstrated depends on the nature of the reason for the out-of-service equipment. For routine out-of-service periods caused by preventative maintenance, etc., the pump and valve operability checks will be performed to demonstrate operability of the remaining components. However, if a failure, design deficiency, cause the outage, then the demonstration of operability should be thorough enough to assure that a generic problem does not exist. For example, if an out-of-service period was caused by failure of a pump to deliver rated capacity due to a design deficiency, the other pumps of this type might be subjected to a flow rate test in addition to the operability checks.

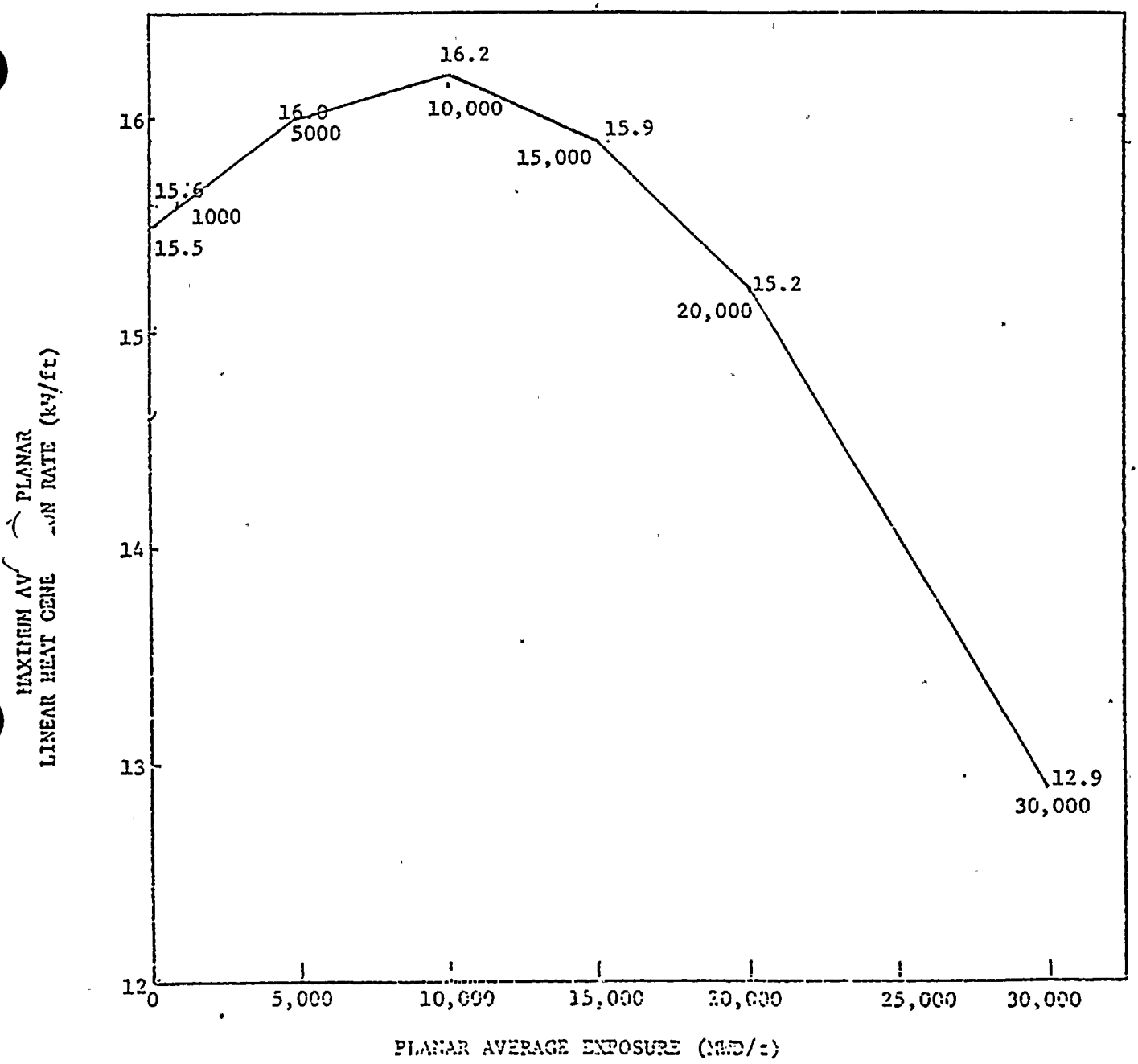
Whenever a CSCS system or loop is made inoperable because of a required test or calibration, the other CSCS systems or loops that are required to be operable shall be considered operable if they are within the required surveillance testing frequency and there is no reason to suspect they are inoperable. If the function, system, or loop under test or calibration is found inoperable or exceeds the trip level setting, the LCO and the required surveillance testing for the system or loop shall apply.

Redundant operable components are subjected to increased testing during equipment out-of-service times. This adds further conservatism and increases assurance that adequate cooling is available should the need arise.

Maximum Average Planar LHGR, LHGR, and MCPR

The MAPLHGR, LHGR, and MCPR shall be checked daily to determine if fuel burnup, or control rod movement has caused changes in power distribution. Since changes due to burnup are slow, and only a few control rods are moved daily, a daily check of power distribution is adequate.

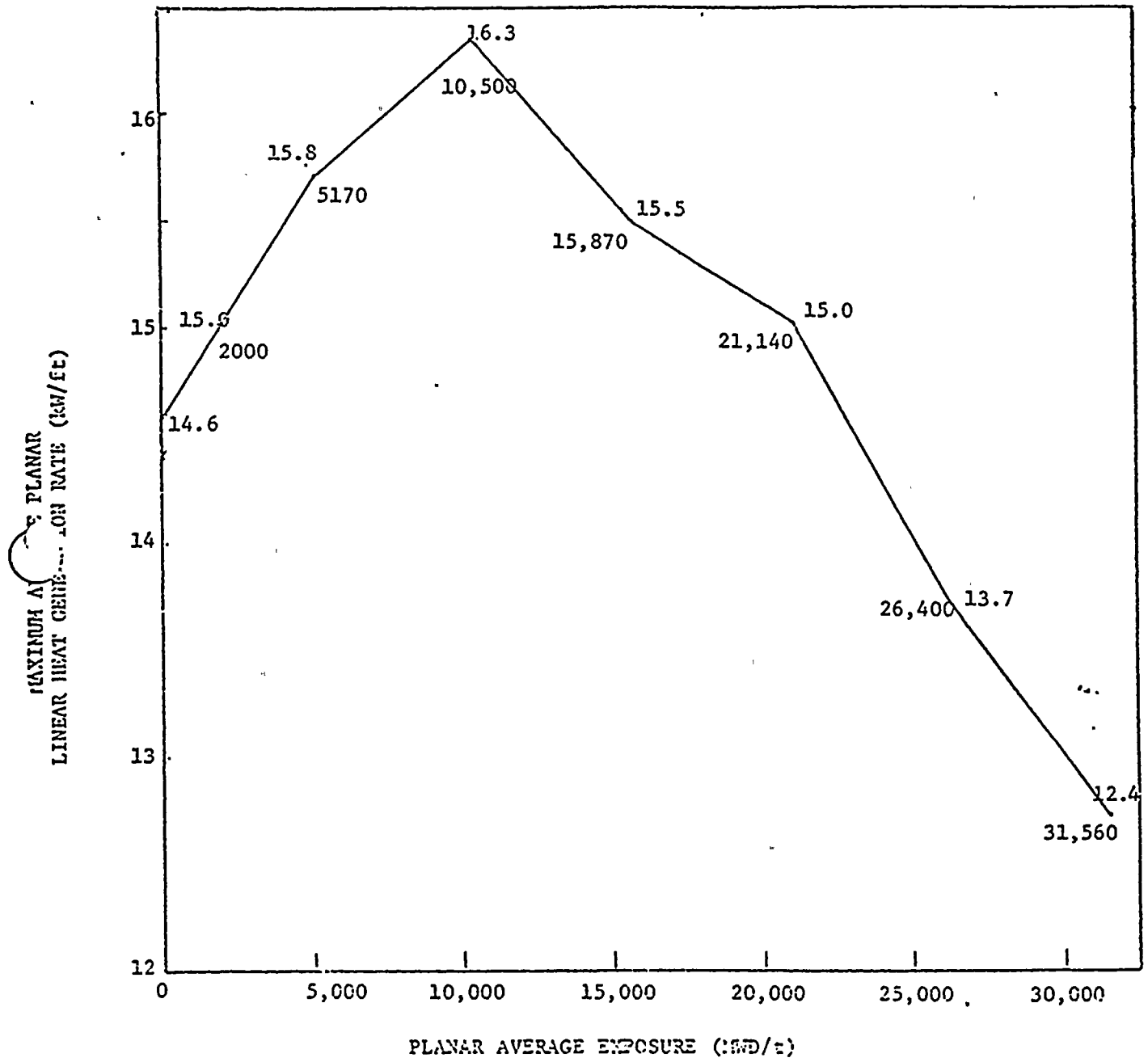
MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR)
VERSUS PLANAR AVERAGE EXPOSURE



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

FIGURE 3.5.1-A
MAPLHGR VS. EXPOSURE
INITIAL CORE FUEL TYPE 2

MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR)
VERSUS PLANAR AVERAGE EXPOSURE



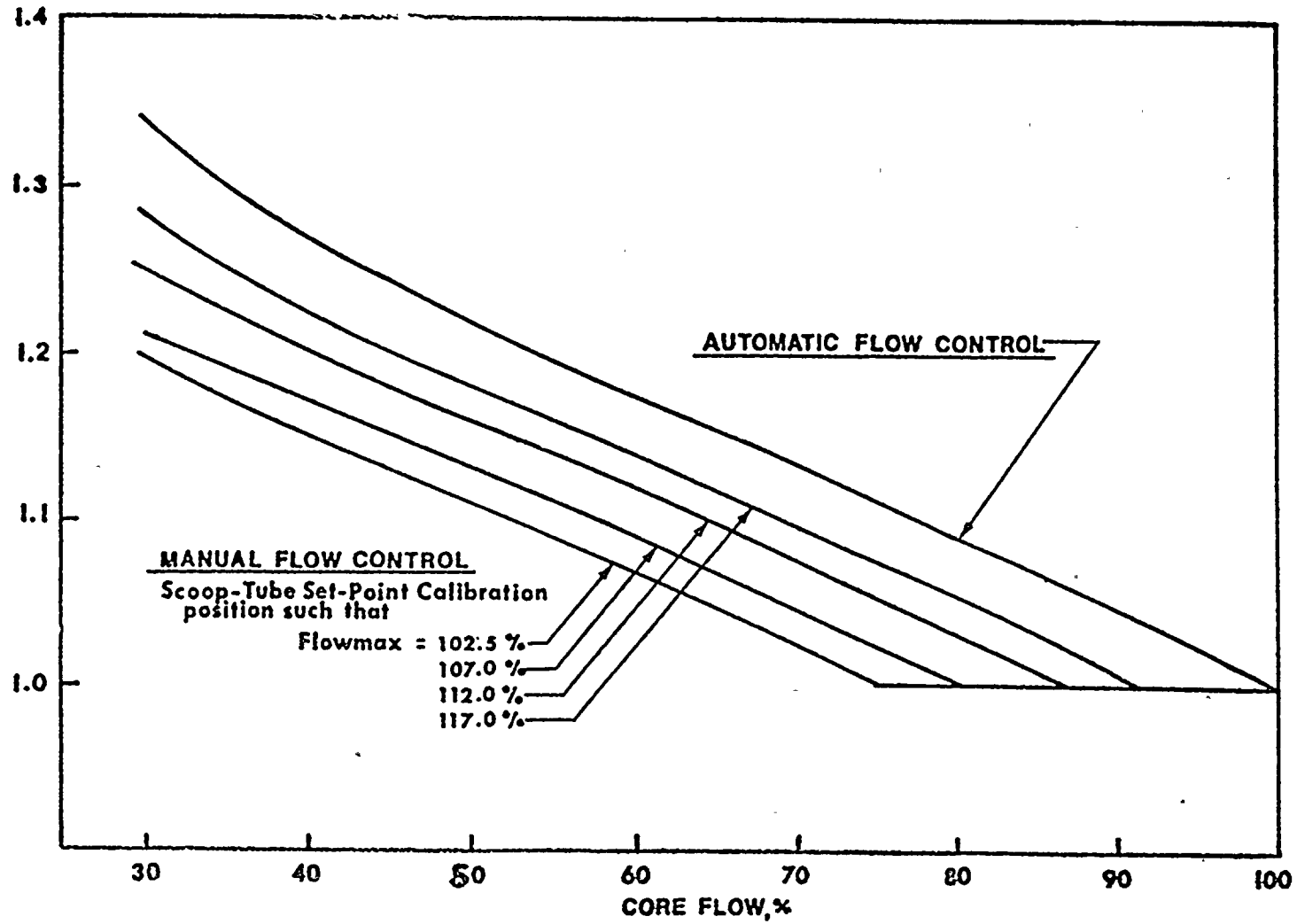
BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

FIGURE 3.5.1-B
MAPLHGR VS. EXPOSURE
INITIAL CORE FUEL TYPES 1 & 3

BROWNS FERRY NUCLEAR PLANT

FIGURE 3.5.2

K_f FACTOR



3.6 PRIMARY SYSTEM BOUNDARY

Applicability

Applies to the operating status of the reactor coolant system.

Objective

To assure the integrity and safe operation of the reactor coolant system.

Specification

A. Thermal and Pressurization Limitations

1. The average rate of reactor coolant temperature change during normal heatup or cooldown shall not exceed 100° F/hr when averaged over a one-hour period.

2. During all operations with a critical core, other than for low level physics tests, except when the vessel is vented, the reactor vessel shell and fluid temperatures shall be at or above the temperature of curve #3 of figure 3.6-1.

4.6 PRIMARY SYSTEM BOUNDARY

Applicability

Applies to the periodic examination and testing requirements for the reactor coolant system.

Objective

To determine the condition of the reactor coolant system and the operation of the safety devices related to it.

Specification

A. Thermal and Pressurization Limitations

1. During heatups and cooldowns, the following parameters shall be recorded and reactor coolant temperature determined at 15-minute intervals until 3 successive readings at each given location are within 5° F.

   a. Steam Dome Pressure (Convert to upper vessel region temperature)

   b. Reactor bottom drain temperature

   c. Recirculation loops A and B

   d. Reactor vessel bottom head temperature

   e. Reactor vessel shell adjacent to shell flange

2. Reactor vessel metal temperature at the outside surface of the bottom head in the vicinity of the control rod drive housing and reactor vessel shell adjacent to shell flange shall be recorded at least every 15 minutes during inservice hydrostatic or leak testing when the vessel pressure is > 312 psig.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.6.A Thermal and Pressurization Limitations	4.6.A Thermal and Pressurization Limitations
3. During heatup by non-nuclear means, except when the vessel is vented, cooldown following nuclear shutdown on low-level physics tests, the reactor vessel temperatures shall be at or above the temperatures of curve #2 of figure 3.6-1.	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. 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.	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 NDTT shift from Figure 3.6-2.
5. The reactor vessel head bolting studs shall not be under tension unless the temperature of the vessel head flange and the head is greater than 100° F.	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. 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.	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. The reactor recirculation pumps shall not be started unless the coolant temperatures between the dome and the bottom head drain are within 145° F.	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

B. Coolant Chemistry

1. Prior to startup and at steaming rates less than 100,000 lb/hr, the following limits shall apply.

   a. Conductivity, µmho/cm@25°C 2.0

   b. Chloride, ppm 0.1

2. At steaming rates greater than 100,000 lb/hr, the following limits shall apply.

   a. Conductivity, µmho/cm@25°C 1.0

   b. Chloride, ppm 0.2

4.6 PRIMARY SYSTEM BOUNDARY

B. Coolant Chemistry

1. Reactor coolant shall be continuously monitored for conductivity.

   a. Whenever the continuous conductivity monitor is inoperable and the condensate demineralizers are bypassed, a sample of reactor coolant shall by analyzed for conductivity every 4 hours. If the condensate demineralizers are in service, a sample of reactor coolant shall be analyzed for conductivity every 8 hours.

   b. Once a week the continuous monitor shall be checked with an in-line flow cell. This in-line conductivity calibration shall be performed every 24 hours whenever the reactor coolant conductivity is >1.0 µmho/cm at 25°C.

2. During startup prior to pressurizing the reactor above atmospheric pressure, measurements of reactor water quality shall be performed to show conformance with 3.6.B.1. of limiting conditions.

3.6 PRIMARY SYSTEM BOUNDARY

3. At steaming rates greater than 100,000 lb/hr, the reactor water quality may exceed specification 3.6.B.2 only for the time limits specified below. Exceeding these time limits of the following maximum quality limits shall be cause for placing the reactor in the cold shutdown condition.

a. Conductivity time above 1 μmho/cm@25°C - 2 weeks/year. Maximum Limit 10 μmho/cm@25°C

b. Chloride concentration time above 0.2 ppm - 2 weeks/year. Maximum Limit - 0.5 ppm.

c. The reactor shall be shutdown if pH <5.6 or >8.6 for a 24 hour period.

4.6 PRIMARY SYSTEM BOUNDARY

3. Whenever the reactor is operatin; (including hot standby condition: measurements of reactor water quality shall be performed according to the following schedule:

a. Chloride ion content shall be measured at least once every 96 hours.

b. Chloride ion content shall be measured at least every 8 hours whenever reactor conductivity is >1.0 μmho/cm at 25°C.

c. A sample of primary coolant shall be measured for pH at least once every 8 hours whenever the reactor coolant conductivity is >1.0 μmho/cm at 25°C.

3.6 PRIMARY SYSTEM BOUNDARY

4. When the reactor is not pressurized, except during startup, the reactor water shall be maintained within the following limits.

   a. Conductivity - 10 μmho/cm@25°C

   b. Chloride - 0.5 ppm

   c. pH shall be between 5.3 and 8.6.

5. When the time limits or maximum conductivity or chloride concentration limits are exceeded, an orderly shutdown shall be initiated immediately. The reactor shall be brought to the cold shutdown condition as rapidly as cooldown rate permits.

4.6 PRIMARY SYSTEM BOUNDARY

4. Whenever the reactor is not pressurized, a sample of the reactor coolant shall be analyzed at least every 96 hours for chloride ion content and pH.

5. During equilibrium power operation an isotopic analysis, including quantitative measurements for at least I-131, I-132, I-133, and I-134 shall be performed monthly on a coolant liquid sample.

3.6 PRIMARY SYSTEM BOUNDARY

6. Whenever the reactor is critical, the limits on activity concentrations in the reactor coolant shall not exceed the equilibrium value of 3.2 μc/gm of dose equivalent* I-131.

This limit may be exceeded following power transients for a maximum of 48 hours. During this activity transient the iodine concentrations shall not exceed 26 μCi/gm whenever the reactor is critical. The reactor shall not be operated more than 5 percent of its yearly power operation under this exception for the equilibrium activity limits. If the iodine concentration in the coolant exceeds 26 μCi/gm, the reactor shall be shut down, and the steam lime isolation valves shall be closed immediately.

*That concentration of I-131 which alone would produce the same thyroid dose as the quantity of total iodines actually present.

4.6 PRIMARY SYSTEM BOUNDARY

6. Additional coolant samples shall be taken whenever the reactor activity exceeds one percent of the equilibrium concentration specified in 3.6.B.6 and one of the following conditions are met:

a. During startup
b. Following a significant power change**
c. Following an increase in the equilibrium off-gas level exceeding 10,000 μCi/sec (at the steam jet air ejector) within a 48 hour period.
d. Whenever the equilibrium iodine limit specified in 3.6.B.4 is exceeded.

The additional coolant liquid samples shall be taken at 4 hour intervals for 48 hours, or until a stable iodine concentration below the limiting value (3.2 μCi/gm) is established. However, at least 3 consecutive samples ahall be taken in all cases. An isotopic analysis shall be performed for each sample, and quantitative measurements made to determine the dose equivalent I-131 concentration. If the total iodine activity of the sample is below 0.32 μci/gm, an isotopic analysis to determine equivalent I-131 is not required.

**For the purpose of this section on sampling frequency, a significant power exchange is defined as a change exceeding 15% of rated power in less than 1 hour.

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.

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.C Coolant Leakage

3. If the condition in 1 or 2 above cannot be met, an orderly shutdown shall be initiated and the reactor shall be shutdown in the Cold Condition within 24 hours.

D. Safety and Relief Valves

1. When more than one valve, safety or relief, is known to be failed, an ordery shutdown shall be initiated and the reactor depressurized to less than 105 psig within 24 hours.

E. Jet Pumps

1. Whenever the reactor is in the startup or run modes, all jet pumps shall be operable. If it is determined that a jet pump is inoperable, or if two or more jet pump flow instrument failures occur and cannot be corrected within 12 hours, an orderly shutdown shall be initiated and the reactor shall be shutdown in the Cold Condition within 24 hours.

4.6.C Coolant Leakage

D. Safety and Relief Valves

1. At least one safety valve and approximately one-half of all relief valves shall be bench-checked or replaced with a bench-checked valve each operating cycle. All 13 valves (2 safety and 11 relief) will have been checked or replaced upon the completion of every second cycle.

2. Once during each operating cycle, each relief valve shall be manually opened until thermocouples downstream of the valve indicate steam is flowing from the valve.

3. The integrity of the relief/safety valve bellows shall be continuously monitored.

4. At least one relief valve shall be disassembled and inspected each operating cycle.

E. Jet Pumps

1. Whenever there is recirculation flow with the reactor in the startup or run modes with both recirculation pumps running, jet pump operability shall be checked daily by verifying that the following conditions do not occur simultaneously:

   a. The two recirculation loops have a flow imbalance of 15% or more when the pumps are operated at the same speed.

3.6.E Jet Pumps

3.6.F Jet Pump Flow Mismatch

1. When both recirculation pumps are in steady state operation, the speed of the faster pump shall be maintained within 122% the speed of the slower pump when core power is 80% or more of rated power or 135% the speed of the slower pump when core power is below 80% of rated power.

2. If specification 3.6.F.1 cannot be met, one recirculation pump shall be tripped.

3. 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.

4. 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.

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. Jet Pump Flow Mismatch

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

G. Structural Integrity

1. Table 4.6.A together with supplementary notes, specifies the

3.6.G Structural Integrity

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.G Structural Integrity

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
Main steam	-	GMS-6, KMS-24, GMS-32, KMS-104 GMS-15, and GMS-24
RHR	-	DSRHR-4, DSRHR-7, DSRHR-8A
Core Spray	-	DSCS-12, DSCS-11, DSCS-5, and DSCS-4

3.6.G Structural Integrity

4.6.G Structural Integrity

Reactor Cleanup - DSRWC-4, DSRWC-3
DSRWC-6, DSRWC-5

HPCI - THPCI-152
THPCI-153B
THPCI-153
THPCI-154

5. System pressure tests in accordance with article IS-500 of section XI of the ASME code including winter 1972 Addenda. The pressure-temperature limits for these tests will be in accordance with specification 3.6.A.3.

6. For Unit 1 an augmented inservice surveillance program shall be performed to monitor potential corrosive effects of chloride residue released during the March 22, 1975 fire. The augmented inservice surveillance program is specified as follows:

   a. Browns Ferry Mechanical Maintenance Instruction 53, dated September 22, 1975, paragraph 4, defines the liquid penetrant examinations required during the first, second, third and fourth refueling outages following the fire restoration.

   b. Browns Ferry Mechanical Maintenance Instruction 46, dated July 18, 1975, Appendix B, defines the liquid penetrant examinations required during the sixth refueling outage following the fire restoration.

3.6 PRIMARY SYSTEM BOUNDARY

H. Shock Suppressors (Snubbers)

1. During all modes of operation except Cold Shutdown and Refuel, all safety-related snubbers shall be operable except as noted in 3.6.H.2 through 3.6.H.5 below.

4.6 PRIMARY SYSTEM BOUNDARY

H. Shock Suppressors (Snubbers)

The following surveillance requirements apply to all hydraulic snubbers listed in 3.6.H.2.

1. All hydraulic snubbers whose seal material has been demonstrated by operating experience, lab testing or analysis to be compatible with the operating environment shall be visually inspected. This inspection shall include, but not necessarily be limited to, inspection of the hydraulic fluid reservoir, fluid connections, and linkage connections to the piping and anchor to verify their operability in accordance with the following schedule:

Number of Snubbers Found Inoperable During Inspection or During Inspection Interval	Next Required Inspection Interval
0	Operating Cycle ±25%
1	12 months ±25%
2	6 months ±25%
3,4	124 days ±25%
5,6,7	62 days ±25%
≥8	31 days ±25%

The required inspection interval shall not be lengthened more than one step at a time.

3.6 PRIMARY SYSTEM BOUNDARY

2. The snubbers listed in Table 3.6.H are required to protect the primary coolant system or other safety related systems or components and are therefore subject to these specifications.

3. From and after the time that a snubber is determined to be inoperable, continued reactor operation is permissible only during the succeeding 72 hours unless the snubber is sooner made operable or replaced.

4.6 PRIMARY SYSTEM BOUNDARY

Snubbers may be categorized in two groups, "accessible" or "inaccessible" based on their accessibility for inspection during reactor operation. These two groups may be inspected independently according to the above schedule.

2. All hydraulic snubbers whose seal materials are other than ethylene propylene or other material that has been demonstrated to be compatible with the operating environment shall be visually inspected for operability every 31 days.

3. The initial inspection shall be performed within 6 months from the date of issuance of these specifications. For the purpose of entering the schedule in Specification 4.6.H.1, it shall be assumed that the facility had been on a 6 month inspection interval.

3.6 PRIMARY SYSTEM BOUNDARY

4. If the requirements of 3.6.H.1 and 3.6.H.3 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 36 hours.

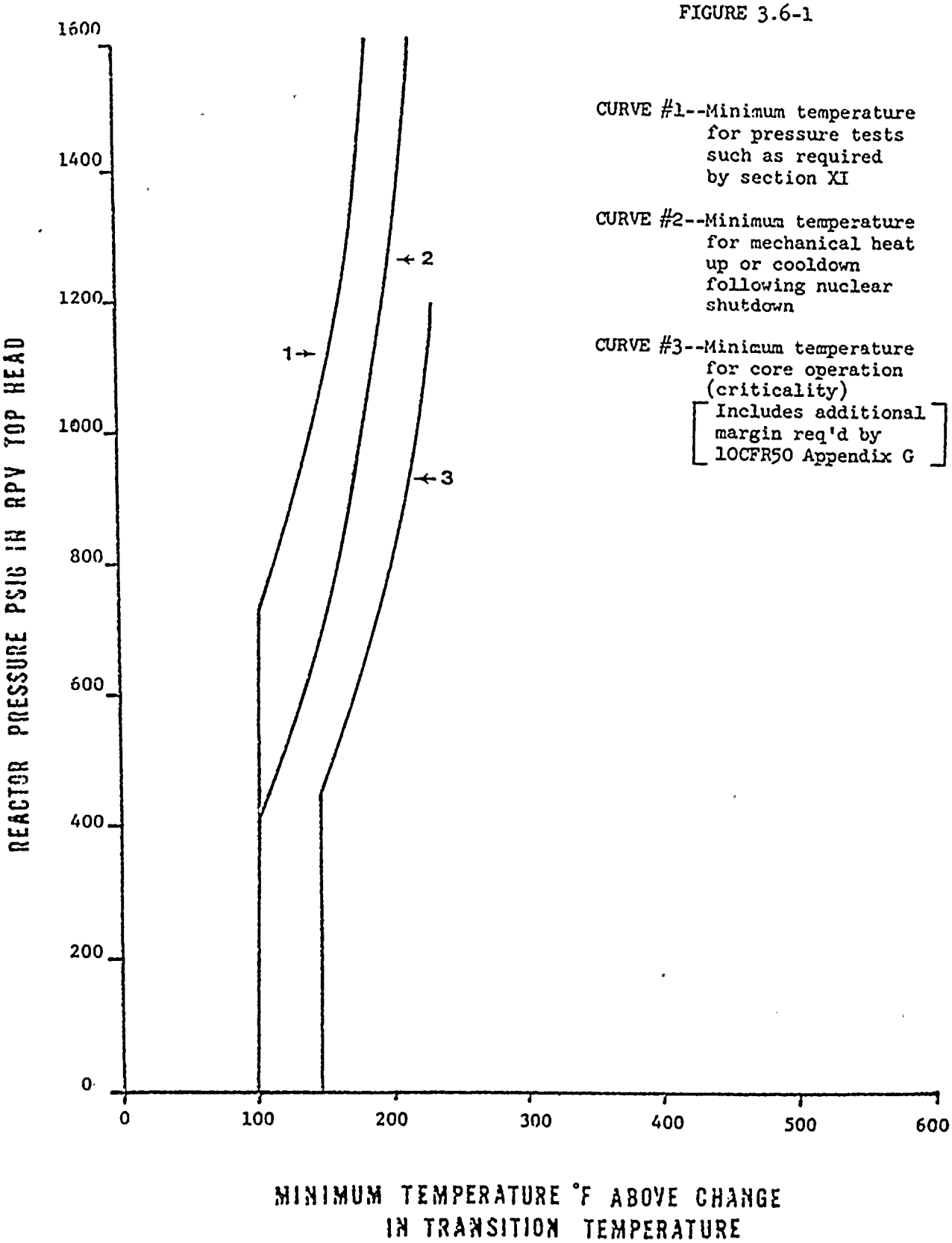
5. If a snubber is determined to be inoperable while the reactor is in the shutdown or refuel mode, the snubber shall be made operable or replaced prior to reactor startup.

6. Snubbers may be added to safety-related systems without prior license amendment to Table 3.6.H provided that a revision to Table 3.6.H is included with a subsequent license amendment request.

4.6 PRIMARY SYSTEM BOUNDARY

4. Once each refueling cycle, a representative sample of 10 snubbers or approximately 10% of the snubbers, whichever is less, shall be functionally tested for operability including verification of proper piston movement, lock up and bleed. For each unit and subsequent unit found inoperable, an additional 10% or ten snubbers shall be so tested until no more failures are found or all units have been tested. Snubbers of rated capacity greater than 50,000 lb need not be functionally tested.

FIGURE 3.6-1



CURVE #1--Minimum temperature for pressure tests such as required by section XI

CURVE #2--Minimum temperature for mechanical heat up or cooldown following nuclear shutdown

CURVE #3--Minimum temperature for core operation (criticality)
[Includes additional margin req'd by 10CFR50 Appendix G]

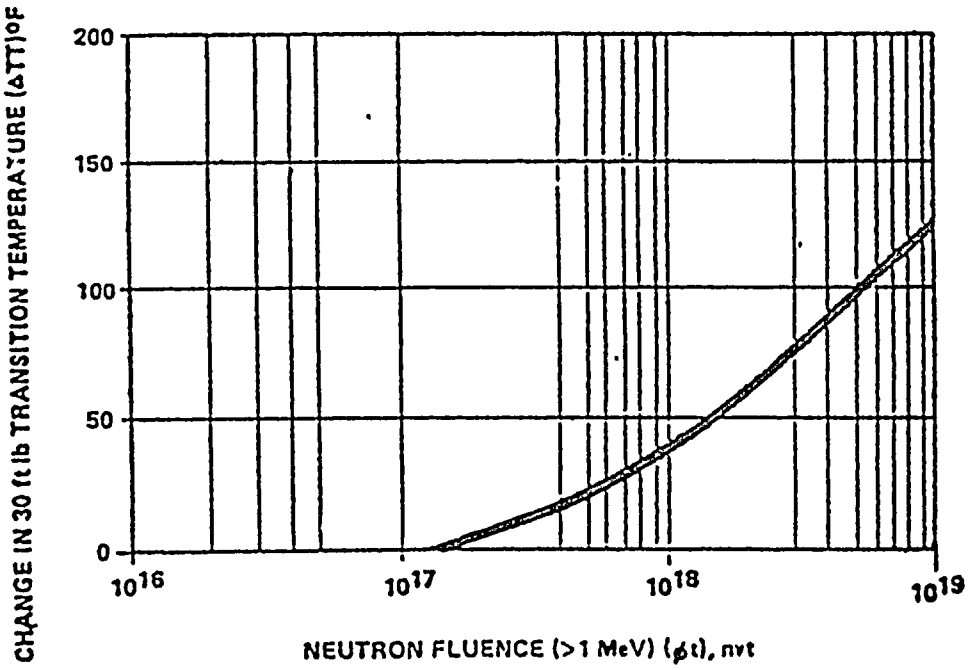


FIGURE 3.6-2
CHANGE IN CHARPY V TRANSITION TEMPERATURE
VERSUS
NEUTRON EXPOSURE

TABLE 6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown *	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
SSA1(Z)	Main Steam A	585			X	
SSA2(X)	Main Steam A	585			X	
SSB1(Z)	Main Steam B	585			X	
SSB2(X)	Main Steam B	585			X	
SSB4(Z)	Main Steam B	585			X	
SSB5(Y)	Main Steam B	585			X	
SSB6(X)	Main Steam B	585			X	
SSC1(Z)	Main Steam C	585			X	
SSC2(X)	Main Steam C	585			X	
SSC4(Z)	Main Steam C	585			X	
SSC5(Y)	Main Steam C	585			X	
SSC6(X)	Main Steam C	585			X	
SSD1(Z)	Main Steam D	585			X	
SSD2(X)	Main Steam D	585			X	
SSA1(X)	Feedwater A	601			X	
SSA2(Z)	Feedwater A	601			X	
SSA3(Y)	Feedwater A	585			X	
SSA4(Z)	Feedwater A	585			X	

TABLE 3.6.H

UNIT 1 - page 2

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown *	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible Durin Normal Operatio
SSA5(X)	Feedwater A	601			X	
SSA6(Z)	Feedwater A	601			X	
SSA7(Z)	Feedwater A	587			X	
SSA8(X)	Feedwater A	587			X	
SSA9(Z)	Feedwater A	587			X	
SSB1(X)	Feedwater B	601			X	
SSB2(Z)	Feedwater B	601			X	
SSB3(Y)	Feedwater B	585			X	
SSB4(Z)	Feedwater B	585			X	
SSB5(X)	Feedwater B	601			X	
SSB6(Z)	Feedwater B	601			X	
SSB7(Z)	Feedwater B	587			X	
SSB8(X)	Feedwater B	587			X	
SSB9(Z)	Feedwater B	587			X	
R1 - north	RHR	537				X
R1 - east	RHR	537				X
R2	RHR	540				X

TABLE 3.6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown *	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
R3	RHR	531				X
R4 - east	RHR	536				X
R4 - west	RHR	536				X
R6 - north	RHR	540				X
R6 - east	RHR	540				X
R6 - north	RHR	537				X
R7 - west	RHR	537				X
R8 - south	RHR	558				X
R8 - west	RHR	558				X
R9 - north	RHR	577				X
R9 - south	RHR	577				X
R10	RHR	550				X
R12 upper	RHR	550				X
R12 lower	RHR	550				X
R13	RHR	571				X
R14 - east	RHR	571				X
R14 - west	RHR	571				X
R15	RHR	598				X

TABLE 3.6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown *	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
R16 upper	RHR	598				X
R16 lower	RHR	598				X
R19	RHR	555				X
R20 upper	RHR	549				X
R21 - east	RHR	572				X
R21 - west	RHR	572				X
R22	RHR	573				X
R24	RHR	580			X	
R25	RHR	579			X	
R26	RHR	575			X	
R41 inside	RHR	555				X
R41 outside	RHR	555				X
R29	RHR head spray	636			X	
R29	RHR head spray	636			X	
R1	Control rod drive	612			X	
R2	Control rod drive	612			X	

TABLE 3.6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown *	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
R1	Core spray	606			X	
R2	Core spray	606			X	
R6 - north	Core spray	544				X
R6 - south	Sore spray	544				X
R8	Core spray	609			X	
R9	Core spray	609			X	
R13 - north	Core spray	544				X
R13 - south	Core spray	544				X
R19	Standby liquid control	624			X	
R21	Standby liquid control	624				X
R3 - north	HPCI	542				X
R3 - south	HPCI	542				X
R6	HPCI	563			X	X
R9	HPCI	547				X
R11	HPCI	532				
R47	HPCI	532				X
R47	HPCI	532				X

TABLE 6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown *	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
R90	HPCI	540				X
R91 - north	HPCI	538				X
R91 - south	HPCI	538				X
R4 - north	RCIC	528				X
R4 - south	RCIC	528				X
R5 - east	RCIC	538		X		X
R5 - south	RCIC	538				X
R7 - east (upper)	RCIC	548				X
R7 - west (lower)	RCIC	548				X
R9 - north	RCIC	564			X	
R9 - south	RCIC	564			X	
R1 upper	Condensate S&S (ring header)	548				X
R1 lower	Condensate S&S (ring header)	548				X
R2 - north	Condensate S&S (ring header)	548				X
R2 - west	Condensate S&S (ring header)	548				X

TABLE 3.6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown*	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
R3 - east	Condensate S&S (ring header)	548				X
R3 - west	Condensate S&S (Ring header)	548				X
R4 north	Condensate S&S (ring header)	548		X		X
R4 - east	Condensate S&S (ring header)	548		X		X
R5 upper	Condensate S&S (ring header)	548		X		
R5 lower	Condensate S&S (ring header)	548		X		
SSZ-1	PSC (ring header)	525				X
SSX-2	PSC (ring header)	525				X
SSX-3	PSC (ring header)	525				X
SSZ-4	PSC (ring header)	525				X
SSZ-5	PSC (ring header)	525				X
SSX-6	PSC (ring header)	525				X
SSX-7	PSC (ring header)	525				X
SSZ-8	PSC (ring header)	525				X
SSX-3A	PSC (ring header)	525				X

TABLE 3.6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown*	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
SSZ-4A	PSC (ring header)	525				X
SSZ-5A	PSC (ring header)	525				X
SSX-6A	PSC (ring header)	525				X
SSX-7A	PSC (ring header)	525				X
SSZ-8A	PSC (ring header)	525				X
R2 upper	Condensate bypass line	557				X
R2 lower	Condensate bypass line	557				X
R9	Condensate bypass line	557				X
R13 - east	Condensate bypass line	557				X
R13 - west	Condensate bypass line	557				X
R42	EECW	605				X
SS1-A	Recirculation	556			X	
SS1-B	Recirculation	556			X	
SS2-A	Recirculation	558			X	
SS2-B	Recirculation	558			X	

TABLE 3.6.H

SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	System	Elevation	Snubbers in High Radiation Area During Shutdown*	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
SS3-A(295°)	Recirculation	564			X	
SS3-A(335°)	Recirculation	564			X	
SS3-B(115°)	Recirculation	564			X	
SS3-B(154°)	Recirculation	564			X	
SS4-A	Recirculation	570			X	
SS4-B	Recirculation	570			X	
SS5-A(262°)	Recirculation	581			X	
SS5-B(325°)	Recirculation	581			X	
SS5-B(35°)	Recirculation	581			X	
SS5-B(98°)	Recirculation	581			X	
SS6-A	Recirculation	568			X	
SS6-B	Recirculation	568			X	
SS7	Recirculation	564			X	
SS8	Recirculation	564			X	

*Modifications to this Table due to changes in high radiation areas should be submitted to the NRC as part of the next license amendment.

PAGES 199-208 DELETED

Table 4.6.A

REACTOR COOLANT SYSTEM INSERVICE INSPECTION SCHEDULE

	AREAS OF INTEREST	ACCESS	% INSP. IN INSP. INTERVAL	FREQUENCY	METHOD
A.	Reactor Vessel				
1.	Longitudinal and circumferential welds outside core region and in vessel head	Those welds above sacrificial shield and all in closure head are accessible from vessel o.d.	10% of accessible longitudinal 5% of accessible circumferential	Code (1)	Volumetric
2.	Vessel-to-flange circumferential weld	From flange surface	100%	Code (2)	Volumetric
	Head-to-flange circumferential weld	From o.d. of head	100%	Code (2)	Volumetric
3.	Primary nozzle-to-vessel welds and nozzle-to-vessel inside radii	All nozzles 4 inches and greater will be accessible from vessel o.d.	100% welds	Code (2)	
			Inside radii at the 6 and 12 o'clock positions	Code (2)	Volumetric
3a.	CRD housing-to-stub tube and stub tube-to-vessel welds and incore penetration	During refueling from CRD area for signs of leakage	100%	At time of system hydrostat	Visual
4.	Primary nozzles to safe-end Dissimilar Metal welds	All nozzles 4 inches and larger will be accessible	100%	Code (2)	Visual, surface and volumetric
5.	Closure studs and nuts	Studs in place, nuts on removal	100%	Code (2)	Visual, surface and volumetric

Table 4.6.A

REACTOR COOLANT SYSTEM INSERVICE INSPECTION SCHEDULE (Continued)

AREAS OF INTEREST	ACCESS	% INSP. IN INSP. INTERVAL	FREQUENCY	METHOD
6. Closure washers,	On removal	100%	Code (2)	Visual
Bushings	In place, when studs are removed	When made accessible		Visual
7. Integrally welded vessel supports	Two sections 2 feet long each, 18° apart, accessible in support skirt to vessel weld	One foot minimum length 180° apart - two spots	Code (2)	Volumetric
8. Vessel cladding	During refueling - vessel i.d.	6 predetermined patches (36 in.^{2} each)	Code (2)	Visual
9. Vessel internals and integrally welded internal supports	Accessible areas during normal refueling	Accessible areas	First refueling and every third refueling thereafter	Visual
10. Vessel flange-ligaments between threaded stud holes	During refueling	100%	Code (2)	Volumetric
B. Piping Pressure Boundary				
1. Vessel, pump, and valve safe ends-to-primary pipe dissimilar metal welds and safe ends in branch piping welds 4 inches and larger	From pipe o.d.	100%	Code (2)	Visual and surfac and volumetric

Table 4.6.A

REACTOR COOLANT SYSTEM INSERVICE INSPECTION SCHEDULE (Continued)

AREAS OF INTEREST	ACCESS	% INSP. IN INSP. INTERVAL	FREQUENCY	METHOD
2. Circumferential and longitudinal pipe welds 4 inches and over	Removable insulation	25% of circumferential welds plus 1 foot of adjacent longitudinal welds	Code (2)	Visual and volumetric
Circumferential-type welds - pipe whip protection	Removable Insulation	All those listed in Section 4.6.G.4 of Technical Specifications	Code (1)	Visual and volumetric
3. Pressure-retaining bolting	2 inches and larger	100%	Code (1)	Visual and volumetric
	Bolting under 2 inches on piping 4 inches and over	100%	Signs of leakage during normal maintenance	Visual
4. Piping supports and hangers				
(a) Integrally welded	Scaffolding - as required	100% visual, 25% Vol. (if suitable geometry)	Code (2)	Visual and volumetric
(b) Nonintegrally welded supports	Scaffolding - as required	100%	Code (2)	Visual
C. Pump Pressure Boundary				
1. Pump casing				
Pump pressure boundary interior	From pump i.d. only when maintenance requires removal of internals	One pump with or without welds if disassembled	Code (1) if disassembled	Visual

Table 4.6.A
REACTOR COOLANT SYSTEM INSERVICE INSPECTION SCHEDULE (Continued)

AREAS OF INTEREST	ACCESS	% INSP. IN INSP. INTERVAL	FREQUENCY	METHOD
2. Pressure-retaining bolting	2 inches and larger	100%	Code (1)	Visual and volumetric
	Bolting under 2 inches	100%	Signs of leakage during normal maintenance outage	Visual
3. Supports				
a. Integrally welded	Scaffolding as required	25%	Code (2)	Visual and volumetric
b. Nonintegrally welded	Scaffolding as required	100%	Code (2)	Visual
4. Nozzle-to-safe end dissimilar metal welds	Removable insulation	100%	Code (2)	Visual and volumetric
D. Valve Pressure Boundary				
1. Valve body seam welds	From valve o.d.	100%	Code (1)	Visual and volumetric
Valve pressure boundary interior	From valve i.d. only when maintenance requires removal of internals	One valve with or without welds if disassembled	Code (1) if disassembled	Visual
2. Valve-to-safe end dissimilar metal welds	Removal insulation	100%	Code (2)	Visual and volumetric

Table 4.6.A

REACTOR COOLANT SYSTEM INSERVICE INSPECTION SCHEDULE (Continued)

AREAS OF INTEREST	ACCESS	% INSP. IN INSP. INTERVAL	FREQUENCY	METHOD
3. Pressure-retaining bolting	2 inches and larger	100%	Code (1)	Visual and volumetric
	Bolting under 2 inches	100%	Signs of leakage during normal maintenance outage	Visual
4. Supports and hangers -				
a. Integrally welded	Scaffolding - as required	25% Vol. (if suitable geometry) 100% visual	Code (2)	Visual and volumetric
b. Nonintegrally welded	Scaffolding - as required	100%	Code (2)	Visual

Table 4.6.A

REACTOR COOLANT SYSTEM INSERVICE INSPECTION SCHEDULE (Continued)

Inspection Frequency:

Code (1) - Program such that all areas of interest will be inspected during the inspection interval.

Code (2) - Program such that at least 25% of the required examinations shall have been completed after one-third of the inspection interval has expired (with credit for no more than 33-1/3% if additional examinations are completed) and at least 50% after two-thirds of the inspection interval has expired (with credit for no more than 66-2/3%). The remainder shall be completed by the end of the inspection interval.

3.6.A/4.6.A Thermal and Pressurization Limitations

The vessel has been analyzed for stresses caused by thermal and pressure transients. Heating and cooling transients throughout plant life at uniform rates of 100° F per hour were considered in the temperature range of 100 to 546° F and were shown to be within the requirements for stress intensity and fatigue limits of Section III of the ASME Boiler and Pressure Vessel Code (65 Edition including Summer 1966 addenda).

Operating limits on the reactor vessel pressure and temperature during normal heatup and cooldown, and during inservice hydrostatic testing, were established using Appendix G of the Summer 1972 Addenda to Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition, as a guide. These operating limits assure that a large postulated surface flaw, having a depth of one-quarter of the material thickness, can be safely accommodated in regions of the vessel shell remote from discontinuities. For the purpose of setting these operating limits the reference temperature, RTNDT, of the vessel material was estimated from impact test data taken in accordance with requirements of the Code to which this vessel was designed and manufactured (65 Edition to Summer 1966 addenda.)

The fracture toughness of all ferritic steels gradually and uniformly decreases with exposure to fast neutrons above a threshold value, and it is prudent and conservative to account for this in the operation of the RPV. Two types of information are needed in this analysis: 1) A relationship between the change in fracture toughness of the RPV steel and the neutron fluence (integrated neutron flux), and b) a measure of the neutron fluence at the point of interest in the RPV wall.

A relationship between neutron fluence and change in Charpy V, 30-foot pound transition temperature has been developed for SA302B/SA533 steel based on at least 35 experimental data points as shown in figure 3.6-2. In turn, this change in transition temperature can be related to a change in the temperature ordinate shown in figure G 2110-1 in Appendix G of Section III of the Boiler Code.

The neutron fluence at any point in the pressure vessel wall can be computed from core physics data. The neutron fluence can also be measured experimentally on the ID of the vessel wall. At present valid experimental measurements can be made only over time periods of less than 5 years because of the limitations of the dosimeter materials. This causes no problem because of the exact relationship between thermal power produced and the number of neutrons produced from a given core geometry. A single experimental measurement in a time period of one year can be used to predict the fluence for the life of the plant in terms of thermal power output if no great changes in core geometry are made.

3.6/4.6 BASES

3.6.A/4.6.A

The vessel pressurization temperatures at any time period can be determined from the thermal power output of the plant and its relation to the neutron fluence and from figure 3.6-2. For heatup or cooldown and core operation, see curves#2 & #3 on figure 3.6-1. During the first fuel cycle, only calculated neutron fluence values can be used. At the first refueling, neutron dosimeter wires which are installed adjacent to the vessel wall can be removed to verify the calculated neutron fluence. As more experience is gained in calculating the fluence the need to verify it experimentally will disappear. Because of the many experimental points used to derive figure 3.6-2, there is no need to reverify if for technical reasons, but in case verification is required for other reasons, three sets of mechanical test specimens representing the base metal, weld metal and weld heat affected zone metal have been placed in the vessel. These can be removed and tested as required.

As described in paragraph 4.2.5 of the safety analysis report, detailed stress analyses have been made on the reactor vessel for both steady-state and transient conditions with respect to material fatigue. The results of these analyses are compared to allowable stress limits. Requiring the coolant temperature in an idle recirculation loop to be within 50°F of the operating loop temerature before a recirculation pump is started assures that the changes in coolant temperature at the reactor vessel nozzles and bottom head region are acceptable.

The coolant in the bottom of the vessel is at a lower temperature than that in the upper regions of the vessel when there is no recirculation flow. This colder water is forced up when recirculation pumps are started. This will not result in stresses which exceed ASME Boiler and Pressure Vessel Code, Section III limits when the temperature differential is not greater than 145°F.

The requirements for cold bolt-up of the reactor vessel closure are based on the NDT temperature plus 60°F which is derived from the requirements of the ASME Code to which the vessel was built. The NDT temperature of the closure flanges, adjacent head and shell material, and stud material is a maximum of 40°F. The minimum temperature for bolt-up is therefore 40 + 60 = 100°F. The neutron radiation fluence at the closure flanges is well below 10^{17} nvt $\geq$ 1Mev and therefore radiation effects will be minor and will not influence this temperature.

3.6.B/4.6.B Coolant Chemistry

Materials in the primary system are primarily 304 stainless steel and the Zircaloy cladding. The reactor water chemistry limits are established to prevent damage to these materials. Limits are placed on conductivity and chloride concentrations. Conductivity is limited because it is continously measured and gives an indication of abnormal conditions and the presence of unusual materials in the coolant. Chloride limits are specified to prevent stress corrosion cracking of stainless steel.

3.6.B/4.6.B Coolant Chemistry

Zircaloy does not exhibit similar stress corrosion failures. However there are some operating conditions under which the dissolved oxygen content of the reactor coolant water could be higher than .2-.3 ppm, such as reactor startup and hot standby. During these periods, the most restrictive limits for conductivity and chlorides have been established. When steaming rates exceed 100,000 lb/hr, boiling deaerates the reactor water. This reduces dissolved oxygen concentration and assures minimal chloride-oxygen content, which together tend to induce stress corrosion cracking.

When conductivity is in its normal range, pH and chloride and other impurities affecting conductivity must also be within their normal range. When conductivity becomes abnormal, then chloride measurements are made to determine whether or not they are also out of their normal operating values. This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are in fact high due to purposeful addition of additives. In the case of BWR's, however, where no additives are used and where near neutral pH is maintained, conductivity provides a very good measure of the quality of the reactor water. Significant changes therein provide the operator with a warning mechanism so he can investigate and remedy the condition causing the change before limiting conditions, with respect to variables affecting the boundaries of the reactor coolant, are exceeded. Methods available to the operator for correcting the off-standard condition include operation of the reactor cleanup system, reducing the input of impurities and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant.

The conductivity of the reactor coolant is continuously monitored. The samples of the coolant which are taken every 96 hours will serve as a reference for calibration of these monitors and is considered adequate to assure accurate readings of the monitors. If conductivity is within its normal range, chlorides and other impurities will also be within their normal ranges. The reactor coolant samples will also be used to determine the chlorides. Therefore, the sampling frequency is considered adequate to detect long-term changes in the chloride ion content. Daily sampling is performed when increased chloride concentrations are most probable. Reactor coolant sampling is increased to once per shift when the continuous conductivity monitor is unavailable.

3.6/4.6 BASES:

The basis for the equilibrium coolant iodine activity limit is a computed dose to the thyroid of 36 rem at the exclusion distance during the 2-hour period following a steam line break. This dose is computed with the conservative assumption of a release of 140,000 lbs of coolant prior to closure of the isolation valves, and a X/Q value of 3.4 x 10^{-4} Sec/m^3.

The maximum activity limit during a short term transient is established from consideration of a maximum iodine inhalation dose less than 300 rem. The probability of a steam line break accident coincident with an iodine concentration transient is significantly lower than that of the accident alone, since operation of the reactor with iodine levels above the equilibrium value is limited to 5 percent of total operation.

The sampling frequencies are established in order to detect the occurrence of an iodine transient which may exceed the equilibrium concentration limit, and to assure that the maximum coolant iodine concentrations are not exceeded. Additional sampling is required following power changes and off-gas transients, since present data indicate that the iodine peaking phenomenon is related to these events.

3.6.C/4.6.C Coolant Leakage

Allowable leakage rates of coolant from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes and on the ability to makeup coolant system leakage in the event of loss of offsite a-c power. The normally expected background leakage due to equipment design and the detection capability for determining coolant system leakage were also considered in establishing the limits. The behavior of cracks in piping systems has been experimentally and analytically investigated as part of the USAEC sponsored Reactor Primary Coolant System Rupture Study (the Pipe Rupture Study). Work utilizing the data obtained in this study indicates that leakage from a crack can be detected before the crack grows to a dangerous or critical size by mechanically or thermally induced cyclic loading, or stress corrosion cracking or some other mechanism characterized by gradual crack growth. This evidence suggests that for leakage somewhat greater than the limit specified for unidentified leakage, the probability is small that imperfections or cracks associated with such leakage would grow rapidly. However, the establishment of allowable unidentified leakage greater than that given in 3.6.C on the basis of the data presently available would be premature because of uncertainties associated with the data. For leakage of the order of 5 gpm, as specified in 3.6.C, the experimental and analytical data suggest a reasonable margin of safety that such leakage magnitude would not result from a crack approaching the critical size for rapid propagation. Leakage less than the magnitude specified can be

detected reasonably in a matter of few hours utilizing the available leakage detection schemes, and if the origin cannot be determined in a reasonably short time the unit should be shut down to allow further investigation and corrective action.

The total leakage rate consists of all leakage, identified and unidentified, which flows to the drywell floor drain and equipment drain sumps.

The capacity of the drywell floor sump pump is 50 gpm and the capacity of the drywell equipment sump pump is also 50 gpm. Removal of 25 gpm from either of these sumps can be accomplished with considerable margin.

REFERENCES

1. Nuclear System Leakage Rate Limits (BFNP FSAR Subsection 4.10)

3.6.D/4.6.D Safety and Relief Valves

The safety and relief valves are required to be operable above the pressure (105 psig) at which the core spray systems is not designed to deliver full flow. 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, as modified by Reference 4, 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 Amendment 22 in response to question 4.1 dated December 6, 1971.

Thirteen safety/relief valves have been installed on each unit with a total capacity of 74% of design 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 1304 psig if a pressure scram is assumed, or 1259 psig margins respectively to the code allowable overpressure limit of 1375 psig. In addition, the same event was analyzed to determine the number of installed valves which must open to limit peak pressure to 1350 psig (25 psig margin). The results of this analysis shows that seven valves must open if a neutron flux scram is assumed or ten valves must open if a pressure scram is assumed.

To meet the second design basis, the total safety/relief capacity of 74% has been divided into 61% relief (11 valves) and 13% 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 FSAR paragraph 14.5.1.2 and Figure 14.5-1. This analysis shows that the 11 relief valves limit pressure at the safety valves to 1168 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 1210 psig which is 165 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 possible 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)

2. Amendment 22 in response to AEC Question 4.2 of December 6, 1971.

3. "Protection Against Overpressure" (ASME Boiler and Pressure Vessel Code, Section III, Article 9)

4. Browns Ferry Nuclear Plant Design Deficiency Report--Target Rock Safety-Relief Valves, transmitted by J. E. Gilleland to F. E. Kruesi, August 29, 1973.

3.6.E/4.6,E Jet Pumps

Failure of a jet pump nozzle assembly holddown mechanism, nozzle assembly and/or riser, would increase the cross-sectional flow area for blowdown following the design basis double-ended line break. Also, failure of the diffuser would eliminate the capability to reflood the core to two-thirds height level following a recirculation line break. Therefore, if a failure occurred, repairs must be made.

The detection technique is as follows. With the two recirculation pumps balanced in speed to within ± 5 percent, the flow rates in both recirculation loops will be verified by control room monitoring instruments. If the two flow rate values do not differ by more than 10 percent, riser and nozzle assembly integrity has been verified.

If they do differ by 10 percent or more, the core flow rate measured by the jet pump diffuser differential pressure system must be checked against the core flow rate derived from the measured values of loop flow to core flow correlation. If the difference between measured and derived core flow rate is 10 percent or more (with the derived value higher) diffuser measurements will be taken to define the location within the vessel of failed jet pump nozzle (or riser) and the unit shut down for repairs. If the potential blowdown flow area is increased, the system resistance to the recirculation pump is also reduced; hence, the affected drive pump will "run out" to a substantially higher flow rate (approximately 115 percent to 120 percent for a single nozzle failure). If the two loops are balanced in flow at the same pump speed, the resistance characteristics cannot have changed. Any imbalance between drive loop flow rates would be indicated by the plant process instrumentation. In addition, the affected jet pump would provide a leakage path past the core thus reducing the core flow rate. The reverse flow through the inactive jet pump would still be indicated by a positive differential pressure but the net effect would be a slight decrease (3 percent to 6 percent) in the total core flow measured. This decrease, together with the loop flow increase, would result in a lack of correlation between measured and derived core flow rate. Finally, the affected jet pump diffuser differential pressure signal would be reduced because the backflow would be less than the normal forward flow.

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

The LPCI loop selection logic has been previously described in the BFNP FSAR. For some limited low probability accidents with the recirculation loop operating with large speed differences, it is possible for the logic to select the wrong loop for injection. For these limited conditions the core spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, a procedural limitation has been placed on the allowable variation in speed between the recirculation pumps.

Analyses indicate that above 80% power the loop select logic could be expected to function at a speed differential up to 14% of their average speed. Below 80% power the loop select logic would be expected to function at a speed differential up to 20% of their average speed. This specification provides margin because the limits are set at ± 10% and ± 15% of the average speed for the above and below 80% power cases, respectively. If the reactor is operating on one pump, the loop select logic trips that pump before making the loop selection.

3.6/4.6 BASES:

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.

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.

It is intended that the required examinations and inspection be completed during each 10-year interval. The periodic examinations are to be done during refueling outages or other extended plant shutdown periods.

Only proven nondestructive testing techniques will be used.

More frequent inspections shall be performed on certain circumferential pipe welds as listed in Section 4.6.G.4 to provide additional protection against pipe whip. These welds were selected in respect to their distance from hangers or supports wherein a failure of the weld would permit the unsupported segments of pipe to strike the drywell wall or nearby auxiliary systems or control systems. Selection was based on judgement from actual plant obsrevation of hanger and support locations and review of drawings. Inspection of all these welds during each 10-year inspection interval will result in there additional examinations above the requirements of Section XI of ASME Code.

An augmented inservice surveillance program is required to determine whether any stress corrosion has occurred in any stainless steel piping, stainless components, and highly stressed alloy steel such as hanger springs, as a result of environmental conditions associated with the March 22, 1975 fire.

REFERENCES

1. Inservice Inspection and Testing (BFNP FSAR Subsection 4.12)

2. Inservice Inspection of Nuclear Reactor Coolant Systems, Section XI, ASME Boiler and Pressure Vessel Code

3. ASME Boiler and Pressure Vessel Code, Section III (1968 edition)

4. American Society for Nondestructive Testing No. SNT-TC-1A (1968 edition)

5. Mechanical Maintenance Instruction 46 (Mechanical Equipment, Concrete, and Structural Stell Cleaning Procedure for Residue From Plant Fire - Units 1 and 2)

6. Mechanical Maintenance Instruction 53 (Evaluation of Corrosion Damage of Piping Components Which Were Exposed to Residue From March 22, 1975 Fire)

7. Plant Safety Analysis (BFNP FSAR subsection 4.12)

3.6.H/4.6.H Shock Suppressors (Snubbers)

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient, while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is therefore required that all hydraulic snubbers required to protect the primary coolant system or any other safety system or component be operable during reactor operation.

Because the snubber protection is required only during relatively low probability events, a period of 72 hours is allowed for repairs or replacements. In case a shutdown is required, the

allowance of 36 hours to reach a cold shutdown condition will permit an orderly shutdown consistent with standard operating procedures. Since plant startup should not commence with knowingly defective safety related equipment, Specification 3.6.H.5 prohibits startup with inoperable snubbers.

All safety related hydraulic snubbers are visually inspected for overall integrity and operability. The inspection will include verification of proper orientation, adequate hydraulic fluid level and proper attachment of snubber to piping and structures.

The inspection frequency is based upon maintaining a constant level of snubber protection. Thus the required inspection interval varies inversely with the observed snubber failures. The number of inoperable snubbers found during a required inspection determines the time interval for the next required inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

Experience at operating facilities has shown that the required surveillance program should assure an acceptable level of snubber performance provided that the seal materials are compatible with the operating environment.

Snubbers containing seal material which has not been demonstrated by operating experience, lab tests or analysis to be compatible with the operating environment should be inspected more frequently (every month) until material compatibility is confirmed or an appropriate changeout is completed.

Examination of defective snubbers at reactor facilities and material tests performed at several laboratories (Reference 1) has shown that millable gum polyurethane deteriorates rapidly under the temperature and moisture conditions present in many snubber locations. Although molded polyurethane exhibits greater resistance to these conditions, it also may be unsuitable for application in the higher temperature environments. Data are not currently available to precisely define an upper temperature limit for the molded polyurethane. Lab tests and in-plant experience indicate that seal materials are available, primarily ethylene propylene compounds, which should give satisfactory performance under the most severe conditions expected in reactor installations.

To further increase the assurance of snubber reliability, functional tests should be performed once each refueling cycle.

These tests will include stroking of the snubbers to verify proper piston movement, lock-up and bleed. Ten percent or ten snubbers whichever is less, represents an adequate sample for such tests. Observed failures on these samples should require testing of additional units. Those snubbers designated in Table 3.6.H as being in high radiation areas or especially difficult to remove need not be selected for functional tests provided operability was previously verified.

Snubbers of rated capacity greater than 50,000 lb. are exempt from the functional testing requirements because of the impracticability of testing such large units.

REFERENCES

1. Report, H. R. Erickson, Bergen Paterson to K. R. Goller, NRC, October 7, 1974, Subject: Hydraulic Shock Sway Arrestors

3.7 CONTAINMENT SYSTEMS

Applicability

Applies to the operating status of the primary and secondary containment systems.

Objective

To assure the integrity of the primary and secondary containment systems.

Specification

A. Primary Containment

1. At any time that the irradiated fuel is in the reactor vessel, and the nuclear system is pressurized above atmospheric pressure or work is being done which has the potential to drain the vessel, the pressure suppression pool water volume and temperature shall be maintained within the following limits except as specified in 3.7.A.2.

   a. Minimum water volume - 123,000 ft^3

   b. Maximum water volume - 135,000 ft^3

   c. With the suppression pool water temperature > 95°F initiate pool cooling and restore the temperature to ≤ 95°F within 24 hours or be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

4.7 CONTAINMENT SYSTEMS

Applicability

Applies to the primary and secondary containment integrity.

Objective

To verify the integrity of the primary and secondary containment.

Specification

A. Primary Containment

1. Pressure Suppression Chamber

   a. The suppression chamber water level be checked once per day. Whenever heat is added to the suppression pool by testing of the ECCS or relief valves the pool temperature shall be continually monitored and shall be observed and logged every 5 minutes until the heat addition is terminated.

3.7 CONTAINMENT SYSTEMS

d. With the suppression pool water temperature > 105°F during testing of ECCS or relief valves, stop all testing, initiate pool cooling and follow the action in specification 3.7.A.1.c above.

e. With the suppression pool water temperature > 120°F following reactor isolation, depressurize to < 200 psig at normal cooldown rates.

f. With the suppression pool water temperature > 110°F during startup or power operation the reactor shall be scrammed.

4.7 CONTAINMENT SYSTEMS

3.7.A Primary Containment

2. Primary containment integrity shall be maintained at all times when the reactor is critical or when the reactor water temperature is above 212°F. and fuel is in the reactor vessel except while performing "open vessel" physics tests at power levels not to exceed 5 MW(t).

4.7.A Primary Containment

2. Integrated Leak Rate Testing

a. Integrated leak rate tests (ILRT's) shall be performed to verify primary containment integrity. Primary containment integrity is confirmed if the maximum allowable integrated leakage rate, L_a, does not exceed the equivalent of 2 percent of the primary containment volume per 24 hours at the 49.6 psig design pressure, P_p.

b. Integrated leak rate tests may be performed at P_p or at a test pressure, P_t of not less than 25 psig provided the resultant leakage rate, L_t, does not exceed a preestablished fraction of L_a determined as follows:

Prior to initial operation, integrated leak rate tests must be performed at P_t and P_p with the lower pressure test performed first to establish the allowable leak rates (in percent per 24 hours). The leakage rates thus measured shall be identified as L_{tm} and L_{pm} respectively. L_t shall not exceed $L_a \cdot \frac{L_{tm}}{L_{pm}}$ for values

of $\frac{L_{tm}}{L_{pm}} \leq 0.7$.

3.7.A Primary Containment

4.7.A Primary Containment

L_t shall not exceed

$$L_a \left[\frac{P_t}{P_p} \right]^{0.5}$$ for values of

$$\frac{L_{tm}}{L_{pm}} > 0.7.$$

c. 1. Test duration shall be at least 24 hours.

2. Closure of containment isolation valves for the purpose of the test shall be accomplished by the means provided for normal operation of the valves without preliminary exercises or adjustment.

3. Test accuracy shall be verified by supplementary means, such as measuring the quantity of air required to return to the starting point or by imposing a known leak rate to demonstrate the validity of measurements.

d. The allowable operational leakage rate which shall be met prior to resumption of power shall not be greater than 75 percent of L_a if the test pressure is P_p or not greater than 75 percent of L_t if the test pressure is P_t.

e. The ILRT's shall be performed at the following minimum frequency:

Primary Containment

4.7.A Primary Containment

1. Prior to initial unit operation.

2. At approximately three and one-third year intervals so that any ten-year interval would include four ILRT's. These intervals may be extended up to eight months if necessary to coincide with refueling outage.

f. Except for the initial ILRT, all ILRT's shall be performed without leak repairs immediately prior to or during the test. If leak repairs are necessary in order to perform ILRT, they shall be preceded by local leak measurements where possible. The leak rate difference prior to and after repair shall be added to final integrated leak rate results, L_{pm} or L_{tm}. Following each ILRT, if the measured leak rate exceeds L_a, the condition shall be corrected. Following repairs, the integrated leak rate test need not be repeated provided local leakage rate measurements before and after repair demonstrate that the leakage rate reduction achieved by repairs reduces the overall measured integrated leak rate to an acceptable value.

g. Local leak rate tests (LLRT's) shall be performed on the primary containment testable penetrations and isolation valves at not less than 49.6 psig (except for the main steam isolation valves, see 4.7.A.1) each opera-

.7.A Primary Containment

4.7.A Primary Containment

ting cycle. Bolted double-gasketed seals shall be tested whenever the seal is closed after being opened and at least once per operating cycle. Acceptable methods of testing are halide gas detection, soap bubbles, pressure decay, hydrostatically pressurized fluid flow or equivalent.

The personnel air lock shall be tested at a pressure of 49.6 psig during each operating cycle. In addition, following each opening, the personnel air lock shall be leak tested at a pressure of $\geq$ 2.5 psig. The total leakage from all penetrations and isolation valves shall not exceed 60 percent of L_a per 24 hours. Penetrations and isolation valves are identified as follows.

(1) Testable penetrations with double O-ring seals - Table 3.7.B,

(2) Testable penetrations with testable bellows - Table 3.7.C,

(3) Isolation valves - Tables 3.7.D through 3.7.G, and

(4) Testable electrical penetrations - Table 3.7.H

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

(2) If conformance to the criterion of 4.7.A.2.g is not demonstrated

3.7.A Primary Containment

4.7.A Primary Containment

within 48 hours following detection of excessive local leakage, the reactor shall be shutdown and depressurized until repairs are effected and the local leakage meets the acceptance criterion as demonstrated by retest.

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

j. Continuous Leak Rate Monitor

When the primary containment is inerted, the containment shall be continuously monitored for gross leakage by review of the inerting system makeup requirements. This monitoring system may be taken out of service for maintenance but shall be returned to service as soon as practicable.

k. Drywell and Torus Surfaces

The interior surfaces of the drywell and torus above the level one foot below the normal water line and outside surfaces of the torus below the water line shall be visually inspected each operating cycle for deterioration and any signs of structural damage with particular attention to piping connections and supports and for signs of distress or displacement. In the event of an extended relief valve operation when the temperature of the suppression pool exceeds 130°F.,

3.7.A Primary Containment

3. Pressure Suppression Chamber - Reactor Building Vacuum Breakers

a. Except as specified in 3.7.A.3.b below, two pressure suppression chamber-reactor building vacuum breakers shall be operable at all times when primary containment intetrity is required. The set point of the differential pressure instrumentation which actuates the pressure suppression chamber-reactor building vacuum breakers shall be 0.5 psid.

b. From and after the date that one of the pressure suppression chamber-reactor building vacuum breakers is made or found to be inoperable for any reason, reactor operation is permissible only during the succeeding seven days, provided that the repair procedure does not violate primary containment integrity.

4. Drywell-Pressure Suppression Chamber Vacuum Breakers

a. When primary containment is required, all drywell-suppression chamber vacuum breakers shall be operable and positioned in the fully closed position (except during testing) except as specified in 3.7.A.4.b and c, below.

b. One drywell-suppression chamber vacuum breaker may be non-fully closed so long as it is determined to be not more than 3° open as indicated by the position lights.

4.7.A Primary Containment

the reactor shall be placed in cold shutdown and the above inspection shall be performed before the reactor is started up.

3. Pressure Suppression Chamber-Reactor Building Vacuum Breakers

a. The pressure suppression chamber-reactor building vacuum breakers shall be exercised and the associated instrumentation including setpoint shall be functionally tested for proper operation each three months.

b. A visual examination and determination that the force required to open each vacuum breaker (check valve) does not exceed 0.5 psid will be made each refueling outage.

4. Drywell-Pressure Suppression Chamber Vacuum Breakers

a. Each drywell-suppression chamber vacuum breaker shall be exercised through an opening-closing cycle every month.

b. When it is determined that two vacuum breakers are inoperable for opening at a time when operability is requir all other vacuum breaker

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 weight 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 hydrogen & oxygen concentration shall be measured and recorded daily.

3.7 CONTAINMENT SYSTEMS

B. Standby Gas Treatment System

1. Except as specified in Specification 3.7.B.3 below, all three trains of the standby gas treatment system and the diesel generators required for operation of such trains shall be operable at all times when secondary containment integrity is required.

4.7 CONTAINMENT SYSTEMS

B. Standby Gas Treatment System

1. At least once per year, the following conditions shall be demonstrated.

a. Pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches of water at a flow of 9000 cfm (± 10%).

b. The inlet heaters on each circuit are capable of an output of at least 40 kW when tested in accordance with ANSI N510-1975.

c. Air distribution is uniform within 20% across HEPA filters and charcoal adsorbers.

3.7 CONTAINMENT SYSTEMS

2. a. The results of the in-place cold DOP and halogenated hydrocarbon tests at ≥ 10% design flow on HEPA filters and charcoal adsorber banks shall show ≥99% DOP removal and ≥99% halogenated hydrocarbon removal when tested in accordance with ANSI N510-1975.

b. The results of laboratory carbon sample analysis shall show ≥90% radioactive methyl iodide removal when tested in accordance with ANSI N510-1975 (130°C, 95% R.H.).

c. Fans shall be shown to operate within ±10% design flow.

4.7 CONTAINMENT SYSTEMS

2. a. The tests and sample analysis of Specification 3.7.B.2 shall be performed at least once per operating cycle or once every 18 months whichever occurs first for standby service or after every 720 hours of system operation and following significant painting, fire or chemical release in any ventilation zone communicating with the system.

b. Cold DOP testing shall be performed after each complete or partial replacement of the HEPA filter bank or after any structural maintenance on the system housing.

c. Halogenated hydrocarbon testing shall be performed after each complete or partial replacement of the charcoal adsorber bank or after any structural maintenance on the system housing.

3.7 CONTAINMENT SYSTEMS

3. From and after the date that one train of the standby gas treatment system is made or found to be inoperable for any reason, reactor operation and fuel handling is permissible only during the succeeding 7 days unless such circuit is sooner made operable, provided that during such 7 days all active components of the other two standby gas treatment trains shall be operable.

4.7 CONTAINMENT SYSTEMS

d. Each train shall be operated with the heaters on a total of at least 10 hours every month.

e. Test sealing of gaskets for housing doors shall be performed utilizing chemical smoke generators during each test performed for compliance with Specification 4.7.B.2.a and Specification 3.7.B.2.a.

3. a. At least once per year automatic initiation of each branch of the standby gas treatment system shall be demonstrated from each unit's controls.

b. At least once per year manual operability of the bypass valve for filter cooling shall be demonstrated.

3.7 CONTAINMENT SYSTEMS

4. If these conditions cannot be met, the reactor shall be placed in a condition for which the standby gas treatment system is not required.

4.7 CONTAINMENT SYSTEMS

c. When one train of the standby gas treatment system becomes inoperable the other two trains shall be demonstrated to be operable within 2 hours and daily thereafter.

4. When a unit is operating at power:

a. The operator shall log the status of the SGTS once each 8-hour shift and at any other time its operability status changes.

b. The operator shall notify the other unit operators should he remove from service or find inoperable unit components which reduce system availability.

3.7.C Secondary Containment

1. Secondary containment integrity shall be maintained in the reactor zone at all times except as specified in 3.7.C.2.

4.7.C Secondary Containment

1. Secondary containment surveillance shall be performed as indicated below:

   a. A preoperational secondary containment capability test shall be conducted by isolating the reactor building and placing two standby gas treatment system filter trains in operation. Such test shall demonstrate the

3.7.C Secondary Containment

2. If reactor zone secondary containment integrity cannot be maintained the following conditions shall be met:

   a. The reactor shall be made subcritical and Specification 3.3.A shall be met.

   b. The reactor shall be cooled down below 212°F and the reactor coolant system vented.

   c. Fuel movement shall not be permitted in the reactor zone.

   d. Primary containment integrity maintained.

3. Secondary containment integrity shall be maintained in the refueling zone, except as specified in 3.7.C.4.

4.7.C Secondary Containment

capability to maintain 1/4 inch of water vacuum under calm wind (< 5 mph) conditions with a system inleakage rate of not more than 12,000 cfm.

   b. Additional tests shall be performed during the first operating cycle under an adequate number of different environmental wind conditions to enable valid extrapolation of the test results.

   c. Secondary containment capability to maintain 1/4 inch o water vacuum under calm wind (< 5 mph) conditions with a system inleakage rate of not more than 12,000 cfm, shall be demonstrated at each refueling outage prior to refueling.

2. After a secondary containment violation is determined the standby gas treatment system will be operated immediately after the affected zones are isolated from the remainder of the secondary containment to confirm its ability to maintain the remainder of the secondary containment at 1/4-inch of water negative pressure under calm wind conditions.

.7.. Secondary Containment

4. If refueling zone secondary containment cannot be maintained the following conditions shall be met:

a. Handling of spent fuel and all operations over spent fuel pools and open reactor wells containing fuel shall be prohibited.

b. The standby gas treatment system suction to the refueling zone will be blocked except for a controlled leakage area sized to assure the achieving of a vacuum of at least 1/4-inch of water and not over 3 inches of water in all three reactor zones.

4.7.C Secondary Containment

D. Primary Containment Isolation Valves

1. During reactor power operation, all isolation valves listed in Table 3.7.A and all reactor coolant system instrument line flow check valves shall be operable except as specified in 3.7.D.2.

D. Primary Containment Isolation Valves

1. The primary containment isolation valves surveillance shall be performed as follows:

a. At least once per operating cycle the operable isolation valves that are power operated and automatically initiated shall be tested for simulated automatic initiation and closure times.

b. At least once per quarter:

(1) All normally open power operated isolation valves (except for the main steam line power-operated isolation valves) shall be fully closed and reopened.

3.7.D Primary Containment Isolation Valves

2. In the event any isolation valve specified in Table 3.7.A becomes inoperable, reactor power operation may continue provided at least one valve in each line having an inoperable valve is in the mode corresponding to the isolated condition.

3. If Specification 3.7.D.1 and 3.7.D.2 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown condition within 24 hours.

4.7.D Primary Containment Isolation Valves

(2) With the reactor power less than 75% trip main steam isolation valves individually and verify closure time.

c. At least twice per week the main steam line power-operated isolation valves shall be exercised one at a time by partial closure and subsequent reopening.

d. At least once per operating cycle the operability of the reactor coolant system instrument line flow check valves shall be verified.

2. Whenever an isolation valve listed in Table 3.7.A is inoperable, the position of at least one other valve in each line having an inoperable valve shall be recorded daily.

.7 CONTAINMENT SYSTEMS

E. Control Room Emergency Ventilation

1. Except as specified in specification 3.7.E.3 below, both control room emergency pressurization systems and the diesel generators required for their operation shall be operable at all times when any reactor vessel contains irradiated fuel.

2. a. The results of the in-place cold DOP and halogenated hydrocarbon tests at design flows on HEPA filters and charcoal adsorber banks shall show ≥99% DOP removal and ≥99% halogenated hydrocarbon removal when tested in accordance with ANSI N510-1975.

b. The results of laboratory carbon sample analysis shall show ≥90% radioactive methyl iodide removal at a velocity when tested in accordance with ANSI N510-1975 (130°C, 95% R.H.).

4.7 CONTAINMENT SYSTEMS

E. Control Room Emergency Ventilation

1. At least once per operating cycle, not to exceed 18 months, the pressure drop across the combined HEPA filters and charcoal adsorber banks shall be demonstrated to be less than 6 inches of water at system design flow rate (± 10%).

2. a. The tests and sample analysis of Specification 3.7.E.2 shall be performed at least once per operating cycle or once every 18 months, whichever occurs first for standby service or after every 720 hours of system operation and following significant painting, fire or chemical release in any ventilation zone communicating with the system.

b. Cold DOP testing shall be performed after each complete or partial replacement of the HEPA filter bank or after any structural maintenance on the system housing.

3.7 CONTAINMENT SYSTEMS

c. System flow rate shall be shown to be within ±10% design flow when tested in accordance with ANSI N510-1975.

3. From and after the date that one of the control room emergency pressurization systems is made or found to be inoperable for any reason, reactor operation or refueling operations is permissible only during the succeeding 7 days unless such circuit is sooner made operable.

4. If these conditions cannot be met, reactor shutdown shall be initiated and all reactors shall be in cold shutdown within 24 hours for reactor operations and refueling operations shall be terminated within 2 hours.

4.7 CONTAINMENT SYSTEMS

c. Halogenated hydrocarbon testing shall be performed after each complete or partial replacement of the charcoal adsorber bank or after any structural maintenance on the system housing.

d. Each circuit shall be operated at least 10 hours every month.

3. At least once per operating cycle not to exceed 18 months, automatic initiation of the control room emergency pressurization system shall be demonstrated.

4. During the simulated automatic actuation test of this system (see Table 4.2.G), it shall be verified that the following dampers operate as indicated:

Close:	FCO-150A, B, C, D, E, and F
Open:	FCO-151 FCO-152

3.7 CONTAINMENT SYSTEMS

F. Primary Containment Purge System

1. The primary containment shall be normally vented and purged through the primary containment purge system. The standby gas treatment system may be used when primary containment purge system is inoperable.

2. a. The results of the in-place cold DOP and halogenated hydrocarbon tests at design flows on HEPA filters and charcoal adsorber banks shall show ≥99% DOP removal and ≥99% halogenated hydrocarbon removal when tested in accordance with ANSI N510-1975.

   b. The results of laboratory carbon sample analysis shall show ≥85% radioactive methyl iodide removal when tested in accordance with ANSI N510-1975 (130°C. 95% R.H.).

4.7 CONTAINMENT SYSTEMS

F. Primary Containment Purge System

1. At least once per operating cycle, not to exceed 18 months the pressure drop across the combined HEPA filters and charcoal adsorber banks shall be demonstrated to be less than 8.5 inches of water at system design flow rate (± 10%).

2. a. The tests and sample analysis of Specification 3.7.F.2 shall be performed at least once per operating cycle or once every 18 months, whichever occurs first or after 720 hours of system operation and following significant painting, fire, or chemical release in any ventilation zone communicating with the system.

   b. Cold DOP testing shall be performed after each complete or partial replacement of the HEPA filter bank or after any structural maintenance on the system housing.

3.7 CONTAINMENT SYSTEMS

c. System flow rate shall be shown to be within ±10% of design flow when tested in accordance with ANSI N510-1975.

4.7 CONTAINMENT SYSTEMS

c. Haloqenated hydrocarbon testing shall be performed after each complete or partial replacement of the charcoal adsorber bank or after any structural maintenance on the system housing.

3.7 CONTAINMENT SYSTEMS

G. Containment Atmosphere Dilution System (CAD)

1. The Containment Atmosphere Dilution (CAD) System shall be operable with:

   a. Two independent systems capable of supplying nitrogen to the drywell and torus.

   b. A minimum supply of 2500 gallons of liquid nitrogen per system.

2. The Containment Atmosphere Dilution (CAD) System shall be operable whenever the reactor mode switch is in the "RUN" position.

3. If one system is inoperable, the reactor may remain in operation for a period of 30 days provided all active components in the other system are operable.

4. If Specification 3.7.G.1 and 3.7.G.2, or 3.7.G.3 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown condition within 24 hours.

5. Primary containment pressure shall be limited to a maximum of 30 psig during repressurization following a loss of coolant accident.

4.7 CONTAINMENT SYSTEMS

G. Containment Atmosphere Dilution System (CAD)

1. System Operability

   a. At least once per month cycle each solenoid operated air/nitrogen valve through at least one complete cycle of full travel and verify that each manual valve in the flow path is open.

   b. Verify that the CAD System contains a minimum supply of 2500 gals of liquid nitrogen twice per week.

7 CONTAINMENT SYSTEMS

H. Containment Atmosphere Monitoring (CAM System - H_2 and O_2 Analyzer

1. Whenever the reactor is not in cold shutdown, two gas analyzer systems (one oxygen and hydrogen sensing circuit per system) shall be operable for monitoring the drywell.

2. Whenever the reactor is not in cold shutdown, one gas analyzer system (one oxygen and hydrogen sensing circuit per system) shall be operable for monitoring the torus.

3. If specification 3.7.H.1 cannot be met, but one system remains operable, the reactor may be operated for a period of 30 days. If both systems are inoperable, the reactor should be placed in shutdown condition within 24 hours.

4. If specification 3.7.H.2 cannot be met, but one sensing circuit remains operable, the reactor may be operated for a period of 30 days. If both sensing circuits are inoperable, the reactor should be placed in shutdown condition within 24 hours.

4.7 CONTAINMENT SYSTEMS

H. Containment Atmosphere Monitoring (CAM) System - H_2 and O_2 Analyzer

1. Once per month perform a channel calibration using standard gas samples containing a nominal:

   a. Three volume percent hydrogen, balance nitrogen and

   b. Two volume percent oxygen balance nitrogen

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves		Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal
		Inboard	Outboard			
1	Main steamline isolation valves (FCV-1-14,26,37,&51 ;1-15, 27, 38, & 52)	4	4	3 < T < 5	0	GC
1	Main steamline drain isolation valves FCV-1-55 & 1-56	1	1	15	C	SC
1	Reactor Water sample line isolation valves	1	1	5	C	SC
2	RHRS shutdown cooling supply isolation valves FCV-74-48 & 47	1	1	40	C	SC
2	RHRS - LPCI to reactor FCV-74-53, 67		2	30	C	SC
2	Reactor vessel head spray isolation valves FCV-74-77, 78	1	1	30	C	SC
2	RHRS flush and drain vent to suppression chamber FCV-74-102, 103, 119, & 120		4	20	C	SC
2	Suppression Chamber Drain FCV-74-57, 58		2	15	C	SC
2	Drywell equipment drain discharge isolation valves FCV-77-15A, & 15B		2	15	0	GC
2	Drywell floor drain discharge isolation valves FCV-77-2A & 2B		2	15	0	GC

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	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	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
7	RCIC Steamline Drain (FCV-71-6A, 6B)		2	5	O	GC
7	RCIC Condensate Pump Drain (FCV-71-7A, 7B)		2	5	O	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	O	GC
8	TIP Guide Tubes (5)		1 per guide tube	NA	C	GC

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves		Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal
		Inboard	Outboard			
	Standby liquid control system check valves CV 63-526 & 525	1	1	NA	C	Process
	Feedwater check valves CV-3-558, 572, 554, & 568	2	2	NA	0	Process
	Control rod hydraulic return check valves CV-85-576 & 573	1	1	NA	0	Process
	RHRS - LPCI to reactor check valves CV-74-54 & 68	2		NA	C	Process

NOTES FOR TABLE 3.7.A

Key: O = Open

C = Closed

SC = Stays Closed

GC = Goes Closed

Note: Isolation groupings are as follows:

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

1. Reactor Vessel Low Water Level (490")
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 condition:

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 only the following condition:

1. Reactor vessel low water level (490")

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

2. High Drywell pressure

TABLE 3.7.B
TESTABLE PENETRATIONS WITH DOUBLE O-RING SEALS

X-1A	Equipment Hatch
X-1B	" "
X-4	DW Head Access Hatch
X-6	CRD Removal Hatch
X-35A	T.I.P. Drives
X-35B	" "
X-35C	" "
X-35D	" "
X-35E	" "
X-35F	" "
X-35G	" "
X-47	Power Operation Test
X-200A	Supp. Chamber Access Hatch
X-200B	" " " "
X-213A	Suppression Chamber Drain
	DW Flange-Top Head
	Shear Lug Inspection Cover #1
	" " " Hatch #2
	" " " " #3
	" " " " #4
	" " " " #5
	" " " " #6
	" " " " #7
	" " " " #8

TABLE 3.7.C
TESTABLE PENETRATIONS WITH TESTABLE BELLOWS

X-7A	-	Primary Steamline	X-11	-	Steamline to HPCI Turbine
X-7B	-	Primary Steamline	X-12	-	RHR Shutdown Supply Line
X-7C	-	Primary Steamline	X-13A	-	RHR Return Line
X-7D	-	Primary Steamline	X-13B	-	RHR Return Line
X-8	-	Primary Steamline Drain	X-14	-	Reactor Water Cleanup Line
X-9A	-	Feedwater Line	X-16A	-	Core Spray Line
X-9B	-	Feedwater Line	X-16B	-	Core Spray Line
X-10	-	Steamline to RCIC Turbine	X-17	-	RHR Head Spray Line

TABLE 3.7.D
PRIMARY CONTAINMENT ISOLATION VALVES

Valves	Valve Identification	Test Medium	Test Method
1-14	Main Steam	Air(1)	Applied between 1-14 and 1-15
1-15	Main Steam	Air(1)	Applied between 1-14 and 1-15. Inboard valve 1-14 to be water sealed at 25 psig.
1-26	Main Steam	Air(1)	Applied between 1-26 and 1-27
1-27	Main Steam	Air(1)	Applied between 1-26 and 1-27. Inboard valve 1-26 to be water sealed at 25 psig.
1-37	Main Steam	Air(1)	Applied between 1-37 and 1-38
1-38	Main Steam	Air(1)	Applied between 1-37 and 1-38. Inboard valve 1-37 to be water sealed at 25 psig.
1-51	Main Steam	Air(1)	Applied between 1-51 and 1-52.
1-52	Main Steam	Air(1)	Applied between 1-51 and 1-52. Inboard valve 1-51 to be water sealed at 25 psig.
1-55	Main Steam Drain	Water(2)	Applied between 1-55 and 1-56
1-56	Main Steam Drain	Water(2)	Applied between 1-55 and 1-56
12-738	Auxiliary Boiler to RCIC	Water(2)	Applied between 12-738 and 12-741
12-741	Auxiliary Boiler to RCIC	Water(2)	Applied between 12-741 and 12-74[illegible]
32-62	Drywell Compressor Suction	Air(1)	Applied between 32-62 and 32-63
32-63	Drywell Compressor Suction	Air(1)	Applied between 32-62 and 32-63
32-336	Drywell Compressor Return	Air(1)	Applied between 32-2253 and 32-2[illegible]
32-2163	Drywell Compressor Return	Air(1)	Applied between 32-2253 and 32-33
43-13	Reactor Water Sample Lines	Water(2)	Applied between 43-13 and 43-599
43-14	Reactor Water Sample Lines	Water(2)	Applied between 43-14 and 43-599
43-28A	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-226 and 43-28A

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

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
71-3	RCIC Steam Supply	Air(1)	Applied between 71-2 and 71-3
71-39	RCIC Pump Discharge	Water(2)	Applied between 71-37, 71-38, and 71-39
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 73-34, 73-35, and 73-44
74-47	RHR Shutdown Suction	Water(2)	Applied between 74-47 and 74-49
74-48	RHR Shutdown Suction	Water(2)	Applied between 74-48 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, 75-58, 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 and 74-61
74-61	RHR Drywell Spray	Water(2)	Applied between 74-60 and 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 and 74-75

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
74-75	RHR Drywell Spray	Water(2)	Applied between 74-74 and 74-75
74-77	RHR Head Spray	Water(2)	Applied between 74-77 and 74-78
74-78	RHR Head Spray	Water(2)	Applied between 74-77 and 74-78
74-661/662	RHR Shutdown Suction	Water(2)	Applied between 74-660 and 74-661/662
75-25	Core Spray Discharge	Water(2)	Applied between 75-25 and 75-27
75-53	Core Spray Discharge	Water(2)	Applied between 75-53 and 75-55
75-57	Core Spray to Auxiliary Boilers	Water(2)	Applied between 75-57 and 75-58
75-58	Core Spray To Auxiliary Boilers	Water(2)	Applied between 75-57 and 75-58
17	Drywell/Suppression Chamber Nitrogen Purge Inlet	Nitrogen(1)	Applied between 76-17, 76-18, 76-19
76-18	Drywell Nitrogen Purge Inlet	Nitrogen(1)	Applied between 76-17, 76-18, 76-19
76-19	Suppression Chamber Purge Inlet	Nitrogen(1)	Applied between 76-17, 76-18, 76-19
76-24	Drywell/Suppression Chamber Nitrogen Purge Inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
77-2A	Drywell Floor Drain Sump	Water(2)	Applied between 77-2A and 77-2B
77-2B	Drywell Floor Drain Sump	Water(2)	Applied between 77-2A and 77-2B
77-15A	Drywell Equipment Drain Sump	Water(2)	Applied between 77-15A and 77-15B
77-15B	Drywell Equipment Drain Sump	Water(2)	Applied between 77-15A and 77-15B
90-254A	Radiation Monitor Suction	Air(1)	Applied between 90-254A, 90-254B, and and 90-255
90-254B	Radiation Monitor Suction	Air(2)	Applied between 90-254A, 90-254B, and 90-255
-255	Radiation Monitor Suction	Air(2)	Applied between 90-254A, 90-254B, and 90-255

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
90-257A	Radiation Monitor Discharge	Air(1)	Applied between 90-257A and 90-257B
90-257B	Radiation Monitor Discharge	Air(1)	Applied between 90-257A and 90-257B
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
76-215	Containment Atmospheric Monitor	Air(1)	Applied between 76-215 and 76-218
76-217	Containment Atmospheric Monitor	Air	Applied between 76-217 and 76-218
76-220	Containment Atmospheric Monitor	Air	Applied between 76-220 and 76-223
76-222	Containment Atmospheric Monitor	Air	Applied between 76-222 and 76-223
76-225	Containment Atmospheric Monitor	Air	Applied between 76-225 and 76-227
76-226	Containment Atmospheric Monitor	Air	Applied between 76-226 and 76-227
76-229	Containment Atmospheric Monitor	Air	Applied between 76-229 and 76-231
76-230	Containment Atmospheric Monitor	Air	Applied between 76-230 and 76-231
76-237	Containment Atmospheric Monitor	Air	Applied between 76-237 and 76-240
76-239	Containment Atmospheric Monitor	Air	Applied between 76-239 and 76-240
76-242	Containment Atmospheric Monitor	Air	Applied between 76-242 and 76-244
76-243	Containment Atmospheric Monitor	Air	Applied between 76-243 and 76-244
76-248	Containment Atmospheric Monitor	Air	Applied between 76-248 and 76-251
76-250	Containment Atmospheric Monitor	Air	Applied between 76-250 and 76-251
76-253	Containment Atmospheric Monitor	Air	Applied between 76-253 and 76-255
76-254	Containment Atmospheric Monitor	Air	Applied between 76-254 and 76-255
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.

TABLE 3.7.E
SUPPRESSION CHAMBER INFLUENT LINES
STOP-CHECK GLOBE ISOLATION VALVES

Valves	Valve Identification	Test Medium	Test Method
71-14	RCIC Turbine Exhaust	Water	Apply between 71-14 and 71-580
71-32	RCIC Vacuum pump Discharge	Water	Apply between 71-32 and 71-592
73-23	HPCI Turbine Exhaust	Water	Apply between 73-23 and 73-603
73-24	HPCI Turbine Exhaust Drain	Water	Apply between 73-24 and 73-609

TABLE 3.7.F
CHECK VALVES ON SUPPRESSION CHAMBER INFLUENT LINES

Valves	Valve Identification	Test Medium	Test Method
71-580	RCIC Turbine Exhaust	Water	Apply between 71-14 and 71-580
71-592	RCIC Vacuum Pump Discharge	Water	Apply between 71-32 and 71-592
73-603	HPCI Turbine Exhaust	Water	Apply between 73-23 and 73-603
73-609	HPCI Exhaust Drain	Water	Apply between 73-24 and 73-609

TABLE 3.7.G
CHECK VALVES ON DRYWELL INFLUENT LINES

Valves	Valve Identification	Test Medium	Test Method
3-554	Feedwater	Water	Applied between 3-67, and 3-554. Valves 73-45, 73-44, 73-35, and 73-34 are used to form a water seal on 73-45.
3-558	Feedwater	Water	Applied between 3-67 and 3-558
3-568	Feedwater	Water	Applied between 3-66, 3-568, and 69-580. Valves 71-40, 71-39, 71-38, and 71-37 are used to form a water seal on 71-40.
3-572	Feedwater	Water	Applied between 3-66 and 3-572
63-525	Standby Liquid Control Discharge	Water	Applied between 63-525 and 63-527
63-526	Standby Liquid Control Discharge	Water	Applied between 63-526 and 63-527
69-579	RWCU Return	Water	Applied between 3-66, 3-568, 69-579 and 71-40. Valves 71-40, 71-39, 71-38, and 71-37 are used to form a water seal on 71-40.
71-40	RCIC Pump Discharge	Water	Applied between 3-66, 3-568, 69-579 and 71-40.
73-45	HPCI Pump Discharge	Water	Applied between 3-67, 3-559 and 73-45
74-54	RHR LPCI Discharge	Water	Applied between 74-54 and 74-55
74-68	RHR LPCI Discharge	Water	Applied between 74-68 and 74-69
75-26	Core Spray Discharge	Water	Applied between 75-26 and 75-27
75-54	Core Spray Discharge	Water	Applied between 75-54 and 75-55
85-573	CRD Hydraulic Return	Water	Applied between 85-573 and 85-577
85-576	CRD Hydraulic Return	Water	Applied between 85-576 and 85-577

TABLE 3.7.H
TESTABLE ELECTRICAL PENETRATIONS

X-100A	Indication and Control
X-100B	Neutron Monitoring
X-100C	" "
X-100D	" "
X-100E	" "
X-100F	" "
X-100G	CRD Rod Position Indic.
X-101A	Recirc. Pump Power
X-101B	" " "
X-101C	" " "
X-101D	" " "
X-102	Thermocouples
X-103	CRD Rod Position Indic.
X-104A	Indication and Control
X-104B	CRD Position Indic.
X-104C	Neutron Monitor
X-104D	Thermocouples
X-104E	Indication and Control
X-104F	" " "
X-105A	Spare (non-testable)
X-105B	Recirc. Pump Power
X-105C	" " "
X-105D	Spare
X-106A	CRD Rod Position Indic.
X-106B	Neutron Monitoring
X-107A	" "

TABLE 3.7.H (Continued)

X-107B	Spare (testable)
X-108A	Power
X-108B	CRD Rod Position Indic.
X-109	" " " "
X-110A	Power
X-110B	CRD Rod Position Indic.
X-230	Containment Air Monitoring System

PAGE DELETED

3.7.A & 4.7.A Primary Containment

The integrity of the primary containment and operation of the core standby cooling system in combination, limit the off-site doses to values less than those suggested in 10 CFR 100 in the event of a break in the primary system piping. Thus, containment integrity is specified whenever the potential for violation of the primary reactor system integrity exists. Concern about such a violation exists whenever the reactor is critical and above atmospheric pressure. An exception is made to this requirement during initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required. There will be no pressure on the system at this time, thus greatly reducing the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedures will be in effect again to minimize the probability of an accident occurring. Procedures and the Rod Worth Minimizer would limit control worth such that a rod drop would not result in any fuel damage. In addition, in the unlikely event that an excursion did occur, the reactor building and standby gas treatment system, which shall be operational during this time, offer a sufficient barrier to keep offsite doses well below 10 CFR 100 limits.

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

Using the minimum or maximum water volumes given in the specification, containment pressure during the design basis accident is approximately 49 psig which is below the maximum of 62 psig. Maximum water volume of 135,000 ft^3 results in a downcomer submergence of 5'2-3/32" and the minimum volume of 123,000 ft^3 results in submergence approximately 12 inches less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to downcomer submergence, this specification is adequate. The maximum temperature at the end of blowdown tested during the Humbolt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperatures above 170°F.

Should it be necessary to drain the suppression chamber, this should only be done when there is no requirement for core standby cooling systems operatibility Under full power operation conditions, blowdown from an initial suppression chamber water temperature of 95°F results in a peak long term water temperature of 170°F which is sufficient for complete condensation. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is not dependency on containment overpressure.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak temperature of the suppression pool is maintained below 160°F during any period of relief valve operation with sonic conditions at the discharge exit. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressuirzed in a timely manner to avoid the regime of potentially high suppression chamber loadings.

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

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

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

Inerting

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

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

To ensure that the oxygen concentration does not exceed 4% following an accident, liquid nitrogen is maintained on-site for containment atmosphere dilution. About 2260 gallons would be sufficient as a 7-day supply, and replenishment facilities can deliver liquid nitrogen to the site within one day; therefore, a requirement of 2500 gallons is conservative. Following a loss of coolant accident the Containment Air Monitoring (CAM) System continuously monitors the oxygen and hydrogen concentration of the containment volume. Two independent systems (a system consists of one oxygen and one hydrogen sensing circuit) are installed in the drywell and one system is installed in the torus. Each sensor and associated circuit is periodically checked by a calibration gas to verify operation.

Failure of a drywell system does not reduce the ability to monitor system atmosphere as a second independent and redundant system will still be operable. Failure of the torus system would require a reactor shutdown as no means would be available under accident conditions to monitor torus atmosphere. Until a redundant system becomes available in the torus, the monitoring requirements of either a hydrogen or oxygen sensing circuit will be utilized. While this reduces the offered protection slightly, one sensor can be used to prevent a combustible atmosphere. In addition the torus atmosphere will be mixed with the drywell atmosphere through the drywell to torus check valves and any increase in the torus hydrogen or oxygen concentration would proportionally change the drywell atmosphere.

Vacuum Relief

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

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

Initial and Final Condition	Check - On Green - On Red - Off	(Fully closed)
Opening Cycle	Check - Off Green - Off Red - On	(Cracked open) (> 80° Open) (> 3° Open)
Closing Cycle	Check - On Green - On Red - Off	(Fully Closed) (< 30^{0} Open) < 3^{0} Open)

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

If the red light circuit alone is inoperable, the valve shall still be considered fully operable. If the green and red or the green light circuit along is inoperable the valve shall be sonsidered inoperable for

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

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

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

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

During each operating cycle, a leak rate test shall be performed to verify that significant leakage flow paths do not exist between the drywell and suppression chamber. The drywell pressure will be increased by at least 1 psi with respect to the suppression chamber pressure and held constant. The 2 psig set point will not be exceeded. The subsequent suppression chamber pressure transient (if any) will be monitored with a sensitive pressure gauge. If the drywell pressure cannot be increased by 1 psi over the suppression chamber pressure it would be because a significant leakage path exists; in this event the leakage source will be identified and eliminated before power operation is resumed.

With a differential pressure of greater than 1 psig, the rate of change of the suppression chamber pressure must not exceed .25 inches of water per minute as measured over a 10 minute period, which corresponds to about 0.14 lb/sec of containment air. In the event the rate of change exceeds this value then the source of leakage will be identified and eliminated before power operation is resumed.

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

The interior of the drywell is painted with an inorganic zinc primer top-coated with an epoxy coating. This coating provides protection against rusting as well as providing a surface which is decontaminable. The inspection of the paint during each major refueling outage, approximately once per year, assures the paint is intact. Experience with this type of paint at fossil fueled generating stations indicates that the inspection interval is adequate.

The interior surfaces of unit 1 suppression chambers are coated with an organic protective coating of the thermosetting resin type.

The inspection of the coating during each refueling outage, approximately once per year, assures the coating is intact. Dropping the water level to one foot below the normal operating water level enables an inspection of that portion of the suppression chamber where any coating problems would first begin to show. If during periodic surviellance, significant rust spots are detected above the water line, these will be recoated.

Coatings used on drywell and suppression chamber interior surfaces have been tested under simulated DBA conditions and were found to withstand these conditions satisfactorily.

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

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

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

Establishing the test limit of 2.0%/day provides an adequate margin of safety to assure the health and safety of the general public. It is further considered that the allowable leak rate should not deviate significantly.

from the containment design value to take advantage of the design leak-tightness capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as built" condition is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable leak rate (49 psig Method) or the allowable test leak rate (25 psig Method) by 0.75 thereby providing a 25% margin to allow for leakage deterioration which may occur during the period between leak rate tests.

The primary containment leak rate test frequency is based on maintaining adequate assurance that the leak rate remains within the specification. The leak rate test frequency is based on the NRC guide for developing leak rate testing and surveillance of reactor containment vessels. Allowing the test intervals to be extended up to 8 months permits some flexibility needed to have the tests coincide with scheduled or unscheduled shutdown periods.

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

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

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

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

BASES

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

High efficiency particulate air (HEPA) filters are installed before and after the charcoal absorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine absorbers. The charcoal absorbers are installed to reduce the potential release of radioiodine to the environment. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal absorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficency of at least 95 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal absorbers are as specified, the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal absorbers.

Only two of the three standby gas treatment systems are needed to clean up the reactor building atmosphere upon containment isolation. If one system is found to be inoperable, there is no immediate threat to the containment system performance and reactor operation or refueling operation may continue while repairs are being made. If more than one train is inoperable, the plant is brought to a condition where the standby gas treatment system is not required.

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

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

The test frequencies are adequate to detect equipment deterioration prior to significant defects, but the tests are not frequent enough to load the filters, thus reducing their reserve capacity too quickly. That the testing frequency is adequate to detect deterioration was demonstrated by the tests which showed no loss of filter efficiency after 2 years of operation

in the rugged shipboard environment on the NS Savannah (ORNL 3726). Pressure drop across the combined HEPA filters and charcoal adsorbers of less than 6 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Heater capability, pressure drop and air distribution should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon refrigerant shall be performed in accordance with USAEC Report DP-1082. Iodine removal efficiency tests shall follow RDT Standard M-16-1T. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray. emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

All elements of the heater should be demonstrated to be functional and operable during the test of heater capacity. Operation of each filter train for a minimum of 10 hrs each month will prevent moisture buildup in the filters and adsorber system.
With doors closed and fan in operation, DOP aerosol shall be sprayed externally along the full linear periphery of each respective door to check the gasket seal. Any detection of DOP in the fan exhaust shall be considered an unacceptable test result and the gaskets repairs and test repeated.

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

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

3.7.D/4.7.D Primary Containment Isolation Valves

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

BASES

Group 1 - process lines are isolated by reactor vessel low water level (490") 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 (490"). 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.

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

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

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

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

The main steam line isolation valves are functionally tested on a more frequent interval to establish a high degree of reliability.

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

3.7.E/4.7.E Control Room Emergency Ventilation

The control room emergency ventilation system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room emergency ventilation system is designed to automatically start upon control room isolation and to maintain the control room pressure to the design positive pressure so that all leakage should be out leakage.

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

If the system is found to be inoperable, there is not immediate threat to the control room and reactor operation or refueling operation may continue for a limited period of time while repairs are being made. If the system cannot be repaired within seven days, the reactor is shutdown and brought to cold shutdown within 24 hours or refueling operations are terminated.

BASES

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than 6 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report -1082. Iodine removal efficiency tests shall follow RDT Standard M-16-1T. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

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

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

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

3.7.F/4.7.F Primary Containment Purge System

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

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

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

BASES

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

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report - 1082. Iodine removal efficiency tests shall follow RDT Standard M-16-1T. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

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

3.8 RADIOACTIVE MATERIALS

Applicability

Applies to the controlled release of radioactive liquids and gases from the facility.

Objective

To define the limits and conditions for the release of radioactive effluents to the environs to assure that any radioactive releases are as low as practicable and within the limits of 10 CFR Part 20.

Specification

A. Liquid Effluents

1. The radioactivity release concentration in liquid effluents from the station shall not exceed the values specified in 10 CFR Part 20, Appendix B, Table II, Column 2, for unrestricted areas.

2. The release rate of radioactive liquid effluents, excluding tritium and noble gases, shall not exceed 20 curies during any calendar quarter.

3. During release of radioactive wastes, the following conditions shall be met:

4.8 RADIOACTIVE MATERIALS

Applicability

Applies to the periodic test and record requirements and sampling and monitoring methods used for facilities effluents.

Objective

To ensure that radioactive liquid and gaseous releases from the facility are maintained within the limits specified by Specifications 3.8.A and 3.8.B.

Specification

A. Liquid Effluents

1. Facility records shall be maintained of the radioactive concentrations and volume before dilution of each batch of liquid effluent released, and of the average dilution flow and length of time over which each discharge occurred.

2. A representative sample of each batch of liquid effluent released shall be analyzed for the principal gamma-emmitting nuclides.

3. Radioactive liquid waste sampling and activity analysis shall be performed in accordance with Table 4.8.A.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.8.A Liquid Effluents	4.8.A Liquid Effluents
a. Liquid waste activity and flow rate shall be continuously monitored and recorded during release, and the effluent control monitor shall be set to alarm and automatically close the waste discharge valve before exceeding the limits specified in 3.8.A.1 above. If this requirement cannot be met, continued release of liquid effluents shall be permitted only during the succeeding 48 hours provided that, during this 48-hour period, two independent samples of each tank shall be analyzed and two station personnel shall independently check valving before the discharge.	
4. The system as designed to process liquid radwastes shall be maintained and shall be operated to process, liquid radwaste prior to their discharge when it appears that the projected cumulative discharge will exceed 1.25 curies during any calendar quarter.	4. The liquid effluent radiation monitor shall be calibrated at least quarterly by means of a known radioactive source. Each monitor, as described, shall also have an instrument channel test monthly and a sensor check daily.
5. The maximum activity to be contained in one liquid radwaste tank that can be discharged directly to the environs shall not exceed 10 curies.	5. The performance of automatic isolation valves and discharge tank selection valves shall be checked annually.
B. Airborne Effluents	B. Airborne Effluents
1. The release rate for gross activity except for I-131 and particulates with half-lives longer than eight days, shall not exceed:	1. The gross β,γ and particulate activity of gaseous wastes released to the environment shall be monitored and recorded:

3.8.B Airborne Effluents

$$\frac{Q_1}{0.13} + \frac{Q_2}{1.46} \leq 1$$

Q_1 = release rate from building exhaust vents in Ci/sec.

Q_2 = release rate from main stack in Ci/sec.

2. The release rates of I-131 and particulates with half lives greater than eight days released to the environs as part of airborne effluents shall not exceed:

$$\frac{Q_3}{.33} + \frac{Q_4}{44} \leq 1$$

Q_3 = release rate from building exhaust vents in uCi/sec.

Q_4 = release rate from main stack in uCi/sec.

3. The release rate of gross gaseous activity from the plant shall not exceed 0.10 curies/second when averaged over any calendar quarter. When the release rate exceeds 0.05 curies/second for a period of greater than 48 hrs licensee shall notify the Director, Directorate of Licensing, in writing within 10 days.

4. The release rate of I-131 and particulates with half-lives greater than 8 days from the

4.8.B Airborne Effluents

a. For effluent streams having continuous monitoring capability, the activity and flow rate shall be monitored and recorded to enable release rates of gross radioactivity to be determined on an hourly basis.

b. For effluent streams without continuous monitoring capability, the activity shall be monitored and recorded and the releases through these streams shall be controlled so that the release rates from all streams are within the limits specified in 3.8.B.

2. Radioactive gaseous waste sampling and activity analysis shall be performed in accordance with Table 4.8.B.

3. Samples of offgas effluents shall be analyzed at least weekly to determine the identity and quantity of the principal radionuclides being released.

3.8.B Airborne Effluents

plant shall not exceed 0.8 μCi/sec when averaged over any calendar quarter. When the release rate exceeds 0.4 μCi/sec for a period of 1 week, the licensee shall notify the Director, Directorate of Licensing, in writing within 10 days.

5. If the limits of 3.8.B are exceeded, appropriate corrective action, such as an orderly reduction of power, shall be initiated to bring the releases within the limits.

6. Radioactive gaseous wastes released to the environment shall be monitored and recorded.

7. During release of gaseous wastes through the main stack, the following conditions shall be met:

   a. The gross β,γ activity monitor, the iodine sampler and particulate sampler shall be operating.

   b. Isolation devices capable of limiting gaseous release rates from the main stack to within the values specified in 3.8.B.1 above shall be operating.

   c. If, for an effluent release path there is no monitor operable, an equivalent monitor can be substituted to monitor this effluent release path or no effluents shall be released through that effluent release path until such monitor is made available.

4.8.B Airborne Effluents

4. All waste gas monitors shall be calibrated at least quarterly by means of a known radioactive source. Each monitor shall have an instrument channel test at least monthly and a sensor check at least daily.

S. Radioactive gases released from each unit's turbine and reactor building roof vents, the radwaste building roof vents, and the main stack shall be continuously monitored. To accomplish this, at least one reactor building and one turbine building vent monitoring system per unit shall be operating whenever that unit's building ventilation system is in service. Also, one radwaste building system vent monitoring channel shall be operating whenever the radwaste ventilation system is in service. At least one main stack monitoring channel shall be operating whenever any unit's air ejector, mechanical vacuum pump, or a standby gas treatment system train is in service. If normal monitoring systems are not available, temporary monitors or other systems shall be used to monitor effluent. A monitoring channel may be out of service for 4 hours for functional testing and calibration without providing a temporary monitor.

If these requirements are not satisfied for the stack or radwaste monitor, the reactors shall be in the hot shutdown condition within 24 hours for the stack and 10 days for the radwaste vent.

If these requirements are not satisfied for the reactor and turbine building vents, the affected reactor shall be in hot shutdown condition within 10 days.

4.8.B Airborne Effluents

C. Mechanical Vacuum Pump

1. The mechanical vacuum pump shall be capable of being automatically isolated and secured on a signal of high radioactivity in the steam lines whenever the main steam isolation valves are open.

2. If the limits of 3.8.C.1 are not met, the vacuum pump shall be isolated.

D. Miscellaneous Radioactive Materials Sources

1. Source Leakage Test

Each sealed source containing radioactive material in excess of those quantities of byproduct material listed in 10 CFR 30.71 Schedule B and all other sources, including alpha emitters, in excess of 0.1 microcurie, shall be free of $\geq$ 0.005 microcurie of removable contamination. Each sealed source with removable contamination in excess of the above limit shall be immediately withdrawn from use and (a) either decontaminated and (b) disposed of in accordance with Commission regulations.

C. Mechanical Vacuum Pump

At least once during each operating cycle verify automatic securing and isolation of the mechanical vacuum pump.

D. Miscellaneous Radioactive Materials Sources

1. Surveillance Requirements

Tests for leakage and/or contamination shall be performed by the licensee or by other persons specifically authorized by the Commission or an agreement State, as follows:

a. Each sealed source, except startup sources subject to core flux, containing radioactive material, other than Hydrogen 3, with a half-life greater than thirty days and in any form other than gas shall be tested for leakage and/or contamination at intervals not to exceed six months. The leakage test shall be capable of detecting the presence of 0.005 microcurie of radioactive material on the test sample.

b. The periodic leak test required does not apply to sealed sources that are stored and not being used. The sources excepted from this test shall be tested for leakage prior to any use or transfer to another user unless they have been leak tested within six months prior to the date of use or transfer. In the absence of a certification from a transferor indicating that a test has been made within six months prior to the transfer, sealed sources shall not be put into use until tested.

c. Startup sources shall be leak tested prior to and following any repair or maintenance and before being subjected to core flux.

Table 4.8-A

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS

A. Test Tank Release

Sampling Frequency	Type of Activity Analysis	Minimum Detectable Concentration, μCi/ml
Each Batch	Principal Gamma-Emitting Nuclides	5×10^{-7} (2)
One Batch/Month	Dissolved and Entrained Fission and Activation Gases	10^{-5}
Monthly Proportional Composite (1)	Tritium	10^{-5}
	Gross Alpha	10^{-7}
Quarterly Proportional Composite (1)	Sr-89, Sr-90	5×10^{-8}

NOTES:

(1) A proportional sample is one in which the quantity of liquid sampled is proportional to the quantity of liquid waste discharged from the plant.

(2) For certain mixtures of gamma emitters, it may not be possible to measure radionuclides in concentrations near their sensitivity limits when other nuclides are present in the sample in much greater concentrations. Under these circumstances, it will be more appropriate to calculate the concentrations of such radionuclides using observed ratios with those radionuclides which are measurable.

TABLE 4.8-B

Radioactive Gaseous Waste Sampling and Analysis

Sample Type	Sampling Frequency	Type of Activity Analysis	Minimum Detectable (1) Concentration, μc/cc
Gas	(2) Weekly and each purge	Principle Gamma Emitters	10^{-4} (3)
	Monthly and each purge	Tritium	10^{-6}
Charcoal	Weekly(4)	I-131	10^{-12}
	Monthly(4)	I-133, I-135	10^{-10}
Particulates	Weekly(4)	Principal Gamma Emitters (at least for Ba-140, La-140, I-131)	10^{-11}
	Monthly composite of weekly samples	Gross alpha	10^{-11}
	Quarterly Composite of monthly samples	Sr-89,Sr-90	10^{-11}

(1) The above detectability limits for concentrations are based on technical feasibility and on the potential significance in the environment of the quantities released. For some nuclides, lower detection limits may be readily achievable and when nuclides are measured below the stated limits they should also be reported.

(2) Analysis shall also be made within one month of the initial criticality and following each refueling process change or other occurrence which could alter the mixture of radionuclides.

(3) For certain mixtures of gamma emitters, it may not be possible to measure radionuclides at levels near their sensitivity limit when other nuclides are present in the sample at much higher levels. Under these circumstances it will be more appropriate to calculate the levels of such radionuclides using observed ratios with those radionuclides that are measurable.

(4) When the average daily gross radioactivity release rate from a release point equals or exceeds that given in 3.8.B.3 or when the steady state gross radioactivity release rate increases by 50% over the previous corresponding power levels' steady state release rate, the associated iodine and particulate cartridge shall be analyzed to determine the release rate increase for iodines and particulates. When samples are taken more often than that shown, the minimum detectable concentrations will be correspondingly higher.

3.8 BASES

Radioactive waste release levels to unrestricted areas should be kept "as low as practicable" and are not to exceed the concentration limits specified in 10 CFR Part 20. At the same time, these specifications permit the flexibility of operation, compatible with considerations of health and safety, to assure that the public is provided a dependable source of power under unusual operating conditions which may temporarily result in releases higher than the design objectives but still within the concentration limits specified in 10 CFR Part 20. It is expected that by using this operational flexibility under unusual operation conditions, and exerting every effort to keep levels of radioactive materials as low as practicable, the annual releases will not exceed a small fraction of the annual average concentration limits specified in 10 CFR Part 20.

3.8.A Liquid Effluents

Specification 3.8.A.1 requires the licensee to limit the release concentration of radioactive materials in liquid effluents from the station to levels specified in 10 CFR Part 20, Appendix B, Table II, Column 2, for unrestricted areas. This specification provides assurance that no member of the general public can be exposed to liquids containing radioactive materials in excess of limits considered permissible under the Commission's Rules and Regulations.

Specification 3.8.A.2 establishes an upper limit for the release of radioactive liquid effluents, excluding tritium and noble gases, of 20 curies during any calendar quarter. The intent of this specification is to permit the licensee the flexibilty of operation to assure that the public is provided a dependable source of power under unusual operating conditions which may temporarily result in releases higher than the levels normally achievable. Releases of up to 20 curies during any calendar quarter will result in concentrations of radioactive material in liquid effluents at small percentages of the limits specified in 10 CFR Part 20.

Specification 3.8.A.3 requires that suitable equipment to control and monitor the releases of radioactive materials in the liquid effluents are operating during any period these releases are taking place.

Specification 3.8.A.4 requires that the licensee shall maintain and operate the equipment installed in the radwaste system to reduce the release of radioactive materials in liquid effluents to as low as practicable consistent with the requirements of 10 CFR Part 50.36a. In order to keep releases of radioactive materials as low as practicable, the specification requires operation of equipment whenever it appears the projected cumulative release will exceed 1.25 curies during any calendar quarter.

Specification 3.8.A.5 limits the amount of radioactivity that may be inadvertently released to the environment to an amount which is as low as practicable consistent with the requirements of 10 CFR Part 50.36a.

3.8.B Airborne Effluents

Specification 3.8.B.1 provides a method to be used in summing the airborne effluents from the main stack and vents which will assure that the release rate does not exceed 10 CFR Part 20, Table II, Column 1, for unrestricted areas. The constants are determined by the annual average site meteorology and an exposure dose of 500 mrem per year to the whole body.

Specification 3.8.B.2 provides a method to be used in summing airborne I-131 and particulates with half-lives greater than eight days released from the stack and vents to assure that the release rate does not exceed 10 CFR Part 20, Appendix B, Table II, Column 1, for unrestricted areas. The constants are determined by the annual average site meteorology and an exposure dose of 500 mrem per year to the whole body or any organ, and include a factor of 700 to account for reconcentration.

Specification 3.8.B.3 establishes an upper limit for the continuous release of gaseous activity from the plant.

Specification 3.8.B.4 is to monitor the performance of the core. A sudden increase in the activity levels of gaseous releases may be the result of the fuel cladding losing its integrity. Since core performance is of utmost importance in the resulting doses from accidents, a report must be filed within 10 days following the specified increase in gaseous radioactive releases.

Specification 3.8.B.5 is to require the licensee to take such actions, including reducing power or other appropriate measures, as may be necessary to keep the radioactive gaseous releases within specified limits.

Specification 3.8.B.6 and 7 are in accordance with Design Criterion 64.

Specification 3.8.B.8 requires that these gaseous monitoring devices be operating whenever radioactive gases are generated in the plant.

3.8.C/4.8.C Mechanical Vacuum Pump

The purpose of isolating the mechanical vacuum pump line is to limit the release of activity from the main condenser. During an accident, fission products would be transported from the reactor through the main steam lines to the condenser. The fission product radioactivity would be sensed by the main steam line radioactivity monitors which initiate isolation.

4.8.A and 4.8.B BASES

The surveillance requirements given under Specification 4.8.A and 4.8.B provide assurance that liquid and gaseous wastes are properly controlled and monitored during any release of radioactive materials in the liquid and gaseous effluents. These surveillance requirements provide the data for the licensee and the Commission to evaluate the station's performance relative to radioactive wastes released to the environment. Reports on the quantities of radioactive materials released in effluents shall be furnished to the Commission on the basis of Section 6 of these technical specifications. On the basis of such reports and any additional information the Commission may obtain from the licensee or others, the Commission may from time to time require the licensee to take such actions as the Commission deems appropriate.

3.8.D and 4.8.D BASES

The objective of this specification is to assure that leakage from byproduct, source, and special nuclear radioactive material sources does not exceed allowable limits.

3.9 AUXILIARY ELECTRICAL SYSTEM

Applicability

Applies to the auxiliary electrical power system.

Objective

To assure an adequate supply of electrical power for operation of those systems required for safety.

Specification

A. Auxiliary Electrical Equipment

A reactor shall not be started up (made critical) from the cold condition unless four units 1 and 2 diesel generators are operable, both 161-kV transmission lines are operable and supplying power to the plant, and the requirements of 3.9.A.4 through 3.9.A.7 are met.

A reactor shall not be started up (made critical) from the Hot Standby Condition unless all of the following conditions are satisfied:

1. At least one off-site 161-kV transmission line and its common transformer are available and capable of automatically supplying auxiliary power to the shutdown boards.

2. Three units 1 and 2 diesel generators shall be operable.

3. An additional source of power consisting of one of the following:

   a. A second 161-kV transmission line and its

4.9 AUXILIARY ELECTRICAL SYSTEM

Applicability

Applies to the periodic testing requirements of the auxiliary electrical systems.

Objective

Verify the operability of the auxiliary electrical system.

Specification

A. Auxiliary Electrical Equipment

1. Diesel Generators

   a. Each diesel generator shall be manually started and loaded once each month to demonstrate operational readiness. The test shall continue for at least a one-hour period at 75% of rated load or greater.

      During the monthly generator test the diesel generator starting air compressor shall be checked for operation and its ability to recharge air receivers. The operation of the diesel fuel oil transfer pumps shall be demonstrated, and the diesel starting time to reach rated voltage and speed shall be logged.

   b. Once per operating cycle a test will be conducted to demonstrate the emergency diesel generators will start and accept emergency load within

3.9.A Auxiliary Electrical Equipment

common transformer or cooling tower transformer (not parallel with the energized common transformer) capable of supplying power to the shutdown boards.

b. A fourth operable units 1 and 2 diesel generator.

4. Buses and Boards Available

a. Start buses 1A and 1B are energized.

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. Undervoltage relays operable on start buses 1A and 1B and 4-kV shutdown boards, A, B, C, and D.

5. The 250-Volt unit and shutdown board batteries and a battery charger for each battery and associated 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.A Auxiliary Electrical Equipment

the specified time sequence.

c. Once a month the quantity of diesel fuel available shall be logged.

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 ASTM D975-68 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.

3.9.A Auxiliary Electrical Equipment

4.9.A Auxiliary Electrical Equipment

3. Logic Systems

a. Both divisions of the common accident signal logic system shall be tested every 6 months to demonstrate that it will function on actuation of the core spray system of each reactor to provide an automatic start signal to all 4 units 1 and 2 diesel generators.

b. Once every 6 months, the condition under which the 480-Volt load shedding logic system is required shall be simulated using pendant test switches and/or pushbutton test switches to demonstrate that the load shedding logic system would initiate load shedding signals on the diesel auxiliary boards, reactor MOV boards, and the 480-Volt shutdown boards.

4. Undervoltage Relays

a. Once every 6 months, the condition under which the undervoltage relays are required shall be simulated with an undervoltage on start buses 1A and 1B to demonstrate that the diesel generators will start.

b. Once every 6 months, the conditions under which the undervoltage relays are required shall be simulated with an undervoltage on each shutdown board to demonstrate that the associated diesel generator will start.

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.

3.9.B Operation with Inoperable Equipment

Whenever a reactor is in Startup mode or Run mode and not in a cold condition, the availability of electric power shall be as specified in 3.9.A, except as specified herein.

1. From and after the date that one 161-kV line or one common station transformer and its parallel cooling tower transformer or one start bus becomes inoperable, reactor operation is permissible under this condition for seven days.
2. When one of the units 1 and 2 diesel generator is inoperable, continued reactor operation is permissible during the succeeding 7 days, provided that both offsite 161-kV transmission lines and both common station transformers or one common transformer and one cooling tower transformer (not parallel with the energized common transformer) are available, and all of the CS, RHR (LPCI and Containment Cooling) Systems, and the remaining three units 1 and 2 diesel generators are operable. If this requirement cannot be met, an orderly shutdown shall be initiated and both reactors shall be shutdown and in the cold condition within 24 hours.

4.9.B Operation with Inoperable Equipment

1. When one 161-kV line or one common station transformer and its parallel cooling tower transformer or one start bus is found to be inoperable, all units 1 and 2 diesel generators and associated boards must be demonstrated to be operable immediately and daily there after.

2. When one of the units 1 and 2 diesel generator is found to be inoperable, all of the CS, RHR (LPCI and Containment Cooling) Systems and the remaining diesel generators and associated boards shall be demonstrated to be operable immediately and daily thereafter.

3.9.B Operation with Inoperable Equipment

3. When one units 1 and 2 4-kV shutdown board is inoperable, continued reactor operation is permissible for a period not to exceed 5 days, provided that both off-site 161-kV transmission lines and both common station transformers or one common transformer and one cooling tower transformer (not parallel with the energized common transformer) are available and the remaining 4-kV shutdown boards and associated diesel generators, CS, RHR (LPCI and Containment Cooling) Systems, and all 480 V emergency power boards are operable. If this requirement cannot be met, an orderly shutdown shall be initiated and both reactors shall be shutdown and in the cold condition within 24 hours.

4. From and after the date that 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. From and after the date that one of the four 250-volt shutdown

4.9.B Operation with Inoperable Equipment

3. When one 4-kV shutdown board is found to be inoperable, all remaining 4-kV shutdown boards and associated diesel generators, CS and RHR (LPCI and Containment Cooling) Systems supplies by the remaining 4-kV shutdown boards shall be demonstrated to be operable, immediately and daily thereafter.

3.9.B Operation with Inoperable Equipment

board batteries and/or its associated battery board is found to be inoperable for any reason, continued reactor operation is permissible during the succeeding five days in accordance with 3.9.B.4.

6. 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.B Operation with Inoperable Equipment

3.9.C Operation in Cold Shutdown

Whenever both reactors are in cold shutdown condition with irradiated fuel in either reactor, the availability of electric power shall be as specified in section 3.9.A except as specified herein.

1. At least two units 1 and 2 diesel generators and their associated 4-kV shutdown boards shall be operable.

2. An additional source of power consisting of at least one of the following:

   a. One 161-kV transmission line and its associated common station transformer or cooling tower transformer capable of supplying power to the units 1 and 2 shutdown boards.

   b. A third operable diesel generator.

3. At least one 480-V shutdown board for each unit must be operable.

3.9 BASES

The objective of this specification is to assure an adequate source of electrical power to operate facilities to cool the plant 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, the nuclear generating units, 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.

Auxiliary power for Browns Ferry Nuclear Plant is supplied from two sources; either the unit station transformers or from the 161-kV transmission system through the common station transformers or the cooling tower transformers. If a common station transformer is lost, the units can continue to operate since the unit station transformers are in service, the other common station transformer and the cooling tower transformers are 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 eight 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 four remaining systems deliver control power to the 4160-volt shutdown boards.

3.9 BASES

Each 250-volt d-c shutdown board control power supply can receive power from its own battery, battery charger, or from a spare charger. The chargers are powered from normal plant auxiliary power or from the standby diesel-driven generator system. Zero resistance short circuits between the control power supply and the shutdown board are cleared by fuses located in the respective control power supply. Each power supply is located in the reactor building near the shutdown board it supplies. Each battery is located in its own independently ventilated battery room.

The 250-volt d-c 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 safeguards control circuit is annunciated in the main control room of the unit affected. The loss of one 250-volt shutdown board battery affects normal control power only for the 4160-volt shutdown board which it supplies. The station battery supplies loads that are not essential for safe shutdown and cooldown of the nuclear system. This battery was not considered in the accident load calculations.

4.9 BASES

The monthly tests of the diesel generators are primarily to check for failures and deterioration in the system since last use. The diesels will be loaded to at least 75 percent of rated power while engine and generator temperatures are stabilized (about one hour). The minimum 75 percent load will prevent soot formation in the cylinders and injection nozzles. Operation up to an equilibrium temperature ensures that there is no overheat problem. The tests also provide an engine and generator operating history to be compared with subsequent engine-generator test data to identify and to correct any mechanical or electrical deficiency before it can result in a system failure.

The test during refueling outages is more comprehensive, including procedures that are most effectively conducted at that time. These include automatic actuation and functional capability tests to verify that the generators can start and be ready to assume load in 10 seconds. The annual inspection will detect any signs of wear long before failure.

Battery maintenance with regard to the floating charge, equilizing charge, and electrolyte level will be based on the manufacturer's instruction and sound maintenance practices. In addition, written records will be maintained of the battery performance. The plant batteries will deteriorate with time but precipitous failure is unlikely. The type of surveillance called for in this specification is that which has been demonstrated through experience to provide an indication of a cell becoming irregular or unserviceable long before it becomes a failure.

The equalizing charge, as recommended by the manufacturer, is vital to maintaining the Ampere-hour capacity of the battery, and will be applied as recommended.

The testing of the logic systems will verify the ability of the logic systems to bring the auxiliary electrical system to running standby readiness with the presence of an accident signal from any reactor or an undervoltage signal on the start buses or 4-kV shutdown boards.

The periodic simulation of accident signals in conjunction with diesel generator voltage available signals will confirm the ability of the 480-volt load shedding logic system to sequentially shed and restart 480-volt loads if an accident signal were present and diesel generator voltage were the only source of electrical power.

REFERENCES

1. Normal Auxiliary Power System (BFNP FSAR subsection 8.4)

2. Standby A.C. Power Supply and Distribution (BFNP FSAR subsection 8.5)

3. 250-volt D.C. Power Supply and Distribution (BFNP FSAR subsection 8.6)

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 Δk 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

3.10.A Refueling Interlocks

3. The fuel grapple hoist load switch shall be set at ≤ 1,000 lbs.

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.

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:

   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

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 Δk at any time during the maintenance. A control rod on which maintenance is being performed shall be considered inoperable.

3.10.A Refueling Interlocks

refueling interlocks shall be operable.

b. A sufficient number of control rods shall be operable so that the core can be made subcritical with the strongest operable control rod fully withdrawn and all other operable control rods fully inserted, or all directional control valves for remaining control rods shall be disarmed electrically and sufficient margin to criticality shall be demonstrated.

c. If maintenance is to be performed on two control rod drives they must be separated by more than two control cells in any direction.

d. An appropriate number of SRM's are available as defined in specification 3.10.A.

6. Any number of control rods may be withdrawn or removed from the reactor core providing the following conditions are satisfied:

a. The reactor mode switch is locked in the "refuel" position. The refueling interlock which prevents more than one control rod from

4.10.A Refueling Interlocks

3.10.A Refueling Interlocks

being withdrawn may be bypassed on a withdrawn control rod after the fuel assemblies in the cell containing (controlled by) that control rod have been removed from the reactor core. All other refueling interlocks shall be operable.

4.10.A Refueling Interlocks

B. Core Monitoring

1. During core alterations, except as in 3.10.B.2, two SRM's shall be operable, in or adjacent to any quadrant where fuel or control rods are being moved. For an SRM to be considered operable, the following shall be satisfied:

   a. The SRM shall be inserted to the normal operating level. (Use of special moveable, dunking type detectors during initial fuel loading and major core alterations in place of normal detectors is permissible as long as the detector is connected to the normal SRM circuit.)

   b. The SRM shall have a minimum of 3 cps with all rods fully inserted in the core, if one or more fuel assemblies are in the core.

2. During a complete core removal, the SRM's shall have an initial minimum count rate of 3 cps prior to fuel removal, with all rods fully inserted and rendered electrically inoperable. The count rate will diminish during fuel removal. Individual control rods outside the periphery of the then existing fuel matrix may be electrically armed and moved for maintenance after all fuel in the cell containing (controlled by) that control rod have been removed from the reactor core.

B. Core Monitoring

Prior to making any alterations to the core the SRM's shall be functionally tested and checked for neutron response. Thereafter, while required to be operable, the SRM's will be checked daily for response.

3.10.C Spent Fuel Pool Water

1. Whenever irradiated fuel is stored in the spent fuel pool, the pool water level shall be maintained at a depth of 8 1/2 feet or greater above the top of the spent fuel. A minimum of 6-1/2 feet of water shall be maintained over single irradiated fuel assemblies during transfer and handling operations.

2. Whenever irradiated fuel is in the fuel pool, the pool water temperature shall be $\leq$ 150°F.

3. Fuel pool water shall be maintained within the following limits:

   conductivity $\leq$ 10 umhos/cm @25°C

   chlorides $\leq$ 0.5 ppm

4.10.C Spent Fuel Pool Water

1. Whenever irradiated fuel is stored in the spent fuel pool, the water level and temperature shall be recorded daily

2. A sample of fuel pool water shall be analyzed in accordance with the following specifications:

   a. At least daily for conductivity and chloride ion content.

   b. At least once per 8 hours for conductivity and chloride content when the fuel pool cleanup system is inoperable.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.10.D Reactor Building Crane	4.10.D Reactor Building Crane
1. The reactor building crane shall be operable: a. When a spent fuel cask is handled. b. Whenever new or spent fuel is handled with the 5-ton hoist.	1. The following operational checks and inspections shall be performed on the reactor building crane prior to handling of a spent fuel cask and new or spent fuel. (These need not be performed more frequently than quarterly.): a. The cab and pendant controls shall be demonstrated to be operable on both the 125-ton hoist and the 5-ton hoist. b. A visual inspection shall be made to insure structural integrity of the 125-ton hoist, the 5-ton hoist and cask yoke safety wire ropes. c. The overtravel limit switch interlocks, movement speed control and braking operations for the bridge, trolley and hoists, the pendant interlocks, the main-auxiliary hoist operation interlock, and the remote emergency stop shall be functionally tested.
E. Spent Fuel Cask	E. Spent Fuel Cask
1. Upon receipt, an empty fuel cask shall not be lifted until a visual inspection is made of the cask-lifting trunnions and fastening connection has been conducted.	1. Prior to attachment and lifting of an empty spent fuel cask from the shipping trailer, a visual inspection shall be conducted on the lifting trunnions and the fasteners used to connect the trunnion to the cask.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.10.E Spent Fuel Cask	4.10.E Spent Fuel Cask
	2. A visual inspection shall be made of the assembled trunnion on the empty cask to insure proper assembly.
F. Spent Fuel Cask Handling - Refueling Floor	
1. Administrative control shall be exercised to limit the height the spent fuel cask is raised above the refueling floor by the reactor building crane to 6 inches, except for entry into the cask decontamination chamber where height above the floor will be approximately 3 feet.	
2. The spent fuel cask yoke safety links shall be properly positioned at all times except when the cask is in the decontamination chamber.	

3.10 BASES

A. Refueling Interlocks

The refueling interlocks are designed to back up procedural core reactivity controls during refueling operations. The interlocks prevent an inadvertent criticality during refueling operations when the reactivity potential of the core is being altered.

To minimize the possibility of loading fuel into a cell containing no control rod, it is required that all control rods are fully inserted when fuel is being loaded into the reactor core. This requirement assures that during refueling the refueling interlocks, as designed, will prevent inadvertent criticality.

The refueling interlocks reinforce operational procedures that prohibit taking the reactor critical under certain situations encountered during refueling operations by restricting the movement of control rods and the operation of refueling equipment.

The refueling interlocks include circuitry which senses the condition of the refueling equipment and the control rods. Depending on the sensed condition, interlocks are actuated which prevent the movement of the refueling equipment or withdrawal of control rods (rod block).

Circuitry is provided which senses the following conditions:

1. All rods inserted.

2. Refueling platform positioned near or over the core.

3. Refueling platform hoists are fuel-loaded (fuel grapple, frame mounted hoist, monorail mounted hoist).

4. Fuel grapple not full up.

5. Service platform hoist fuel-loaded.

6. One rod withdrawn.

When the mode switch is in the "Re-fuel" position, interlocks prevent the refueling platform from being moved over the core if a control rod is withdrawn and fuel is on a hoist. Likewise, if the refueling platform is over the core with fuel on a hoist, control rod motion is blocked by the interlocks. When the mode switch is in the refuel position only one control rod can be withdrawn. The refueling interlocks, in combination with core nuclear design and refueling procedures, limit the probability of an inadvertent criticality. The nuclear characteristics of the core assure that the reactor is subcritical even when the highest worth control rod is fully withdrawn. The combination of refueling interlocks for control

rods and the refueling platform provide redundant methods of preventing inadvertent criticality even after procedural violations. The interlocks on hoists provide yet another method of avoiding inadvertent criticality.

Fuel handling is normally conducted with the fuel grapple hoist. The total load on this hoist when the interlock is required consists of the weight of the fuel grapple and the fuel assembly. This total is approximately 1,500 lbs, in comparison to the load-trip setting of 1,000 lbs. Provisions have also been made to allow fuel handling with either of the three auxiliary hoists and still maintain the refueling interlocks. The 400-lb load-trip setting on these hoists is adequate to trip the interlock when one of the more than 600-lb fuel bundles is being handled.

During certain periods, it is desirable to perform maintenance on two control rods and/or control rod drives at the same time. The maintenance is performed with the mode switch in the "refuel" position to provide the refueling interlocks normally available during refueling operations. In order to withdraw a second control rod after withdrawal of the first rod, it is necessary to bypass the refueling interlock on the first control rod which prevents more than one control rod from being withdrawn at the same time. The requirement that an adequate shutdown margin be demonstrated or that all remaining control rods have their directional control valves electrically disarmed ensures that inadvertent criticality cannot occur during this maintenance. The adequacy of the shutdown margin is verified by demonstrating that the core is shut down by a margin of 0.38 percent Δk with the strongest operable control rod fully withdrawn, or that at least 0.38% Δk shutdown margin is available if the remaining control rods have had their directional control valves disarmed. Disarming the directional control valves does not inhibit control rod scram capability.

Specification 3.10.A.6 allows unloading of a significant portion of the reactor core. This operation is performed with the mode switch in the "refuel" position to provide the refueling interlocks normally available during refueling operations. In order to withdraw more than one control rod, it is necessary to bypass the refueling interlock on each withdrawn control rod which prevents more than one control rod from being withdrawn at a time. The requirement that the fuel assemblies in the cell controlled by the control rod be removed from the reactor core before the interlock can be bypassed ensures that withdrawal of another control rod does not result in inadvertent criticality. Each control rod provides primary reactivity control for the fuel assemblies in the cell associated with that control rod.

Thus, removal of an entire cell (fuel assemblies plus control rod) results in a lower reactivity potential of the core. The requirements for SRM operability during these core alterations assure sufficient core monitoring.

REFERENCES

1. Refueling interlocks (BFNP FSAR Subsection 7.6)

B. Core Monitoring

The SRM's are provided to monitor the core during periods of station shutdown and to guide the operator during refueling operations and station startup. Requiring two operable SRM's in or adjacent to any core quadrant where fuel or control rods are being moved assures adequate monitoring of that quadrant during such alterations. The requirement of 3 counts per second provides assurance that neutron flux is being monitored and ensures that startup is conducted only if the source range flux level is above the minimum assumed in the control rod drop accident.

Under the special condition of removing the full core with all control rods inserted and electrically disarmed, it is permissible to allow SRM count rate to decrease below 3 cps. All fuel moves during core unloading will reduce reactivity. It is expected that the SRM's will drop below 3 cps before all of the fuel is unloaded. Since there will be no reactivity additions during this period, the low number of counts will not present a hazard. When all of the fuel has been removed to the spent fuel storage pool, SRM's will no longer be required. Requiring the SRM's to be functionally tested prior to fuel removal assures that the SRM's will be operable at the start of fuel removal. The daily response check of the SRM's ensures their continued operability until the count rate diminishes due to fuel removal. Control rods in cells from which all fuel has been removed and which are outside the periphery of the then existing fuel matrix may be armed electrically and moved for maintenance purposes during full core removal, provided all rods that control fuel are fully inserted and electrically disarmed.

REFERENCES

1. Neutron Monitoring System (BFNP FSAR Subsection 7.5)

2. Morgan, W. R.,"In-Core Neutron Monitoring System for General Electric Boiling Water Reactors," General Electric Company, Atomic Power Equipment Department, November 1968, revised April 1969 (APED-5706)

C. Spent Fuel Pool Water

The design of the spent fuel storage pool provides a storage location for approximately 140 percent of the full core load of fuel assemblies in the reactor building which ensures adequate shielding, cooling, and reactivity control of irradiated fuel. An analysis has been performed which shows that a water level at or in excess of eight and one-half feet over the top of the stored assemblies will provide shielding such that the maximum calculated radiological doses do not exceed the limits of 10 CFR 20. The normal water level provides 14-1/2 feet of additional water shielding. The capacity of the skimmer surge tanks is available to maintain the water level at its normal height for three days in the absence of additional water input from the condensate storage tanks. All penetrations of the fuel pool have been installed at such a height that their presence does not provide a possible drainage route that could lower the normal water level more than one-half foot.

3.10.C BASES

The fuel pool cooling system is designed to maintain the pool water temperature less than 125°F during normal heat loads. If the reactor core is completely unloaded when the pool contains two previous discharge batches, the temperature may increase to greater than 125°F. The RHR system supplemental fuel pool cooling mode will be used under these conditions to maintain the pool temperature to less than 125°F.

3.10.D/4.10.D BASES

Reactor Building Crane

The reactor building crane and 125-ton hoist are required to be operable for handling of the spent fuel in the reactor building. The controls for the 125-ton hoist are located in the crane cab. The 5-ton has both cab and pendant controls.

A visual inspection of the load-bearing hoist wire rope assures detection of signs of distress or wear so that corrections can be promptly made if needed.

The testing of the various limits and interlocks assures their proper operation when the crane is used.

3.10.E/4.10.E

Spent Fuel Cask

The spent fuel cask design incorporates removable lifting trunnions. The visual inspection of the trunnions and fasteners prior to attachment to the cask assures that no visual damage has occurred during prior handling. The trunnions must be properly attached to the cask for lifting of the cask and the visual inspection assures correct installation.

3.10.F Spent Fuel Cask Handling - Refueling Floor

Although single failure protection has been provided in the design of the 125-ton hoist drum shaft, wire ropes, hook and lower block assembly on the reactor building crane, the limiting of lift height of a spent fuel cask controls the amount of energy available in a dropped cask accident when the cask is over the refueling floor.

An analysis has been made which shows that the floor and support members in the area of cask entry into the decontamination facility can satisfactorily sustain a dropped cask from a height of 3 feet.

The yoke safety links provide single failure protection for the hook and lower block assembly and limit cask rotation. Cask rotation is necessary for decontamination and the safety links are removed during decontamination.

4.10 BASES

A. Refueling Interlocks

Complete functional testing of all refueling interlocks before any refueling outage will provide positive indication that the interlocks operate in the situations for which they were designed. By loading each hoist with a weight equal to the fuel assembly, positioning the refueling platform, and withdrawing control rods, the interlocks can be subjected to valid operational tests. Where redundancy is provided in the logic circuitry, tests can be performed to assure that each redundant logic element can independently perform its function.

B. Core Monitoring

Requiring the SRM's to be functionally tested prior to any core alteration assures that the SRM's will be operable at the start of that alteration. The daily response check of the SRM's ensures their continued operability.

REFERENCES

1. Fuel Pool Cooling and Cleanup System (BFNP FSAR Subsection 10.5)

2. Spent Fuel Storage (BFNP FSAR Subsection 10.3)

3.11 FIRE PROTECTION SYSTEMS

Applicability:

Applies to operating status of the high pressure water and CO_2 fire protection systems for the reactor building, diesel generator buildings, control bay, intake pumping station, cable tunnel to the intake pumping station, and the fixed spray system for cable trays along the south wall of the turbine buildng, elevation 586.

Objective:

To assure availability of Fire Protection Systems.

Specification:

A. High Pressure Fire Protection System

1. The High Pressure Fire Protection System shall have:

   a. Two (2) high pressure fire pumps operable and aligned to the high pressure fire header.

   b. Automatic initiation logic operable.

4.11 FIRE PROTECTION SYSTEMS

Applicability:

Applies to the surveillance requirements of the high pressure water and CO_2 fire protection systems for the reactor building, diesel generator buildings, control bay, intake pumping station, cable tunnel to the intake pumping station, and the fixed spray system for cable trays along the south wall of the turbine building, elevation 586 when the corresponding limiting conditions for operation are in effect.

Objective:

To verify the operability of the Fire Protection Systems.

Specification:

A. High Pressure Fire Protection System

1. High Pressure Fire Protection System Testing:

Item	Frequency
a. Simulated automatic and manual actuation of high pressure pumps	Once/year
b. Pump Operability	Once/month
c. Automatic valve operability	Once/3 months
d. Pump capability	Once/3 years

3.11 FIRE PROTECTION SYSTEMS

4.11 FIRE PROTECTION SYSTEMS

checked to be 2664 gpm at 250 feet head	
e. Spray header and nozzle inspection for blockage	Once/year
f. System flush in conjunction with semi-annual addition of biocide to the Raw Cooling Water System	Twice/year
g. Building hydraulic performance verification	Once/3 years
h. Yard loop and cooling tower loop hydraulic performance verification	Once/year

3.11 FIRE PROTECTION SYSTEMS

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

3. If only one high pressure fire pump is operable, the reactors may remain in operation for a period not to exceed 7 days, provided the requirements of specification 3.11.A.1.b above are met.

4. If specification 3.11.A.3 cannot be met, the reactors shall be placed in the cold shutdown condition in 24 hours.

5. Removal of any component in the High Pressure Fire System from service for any reason other than testing or emergency operations shall require Plant Superintendent approval.

6. The Raw Service Water storage tank level shall be maintained above level 723'7" by the raw service water pumps.

4.11 FIRE PROTECTION SYSTEMS

2. When it is determined that only one pump is operable, that pump shall be demonstrated operable immediately and daily thereafter until specification 3.11.A.1.a can be met.

3. Raw Service Water System Testing

Item	Frequency
Simulated automatic and manual actuation of raw service water pumps and operation of tank level switches	Once/year

4. The high pressure fire protection system pressure shall be logged daily.

5. Principal header and component isolation valves shall be checked open at intervals no greater than three months.

3.11 FIRE PROTECTION SYSTEMS

7. If specification 3.11.A.6 cannot be met a fire pump shall be started and run continuously until the raw service water pumps can maintain a raw service water storage tank level above 723'7".

8. The fire protection water distribution system shall have a minimum capacity of 2664 gpm at 250' head.

9. The fire protection system shall be capable of supplying the individual loads listed in Table 3.11.A.

4.11 FIRE PROTECTION SYSTEMS

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
d. 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.

3.11 FIRE PROTECTION SYSTEMS

4. If CO_2 fire protection is lost to a cable spreading room or to any diesel generator building area a continuous fire watch shall be established immediately and shall be continued until CO_2 fire protection is restored.

5. Removal of any component in the CO_2 Fire Protection System from service for any reason other than testing or emergency operations shall require Plant Superintendent approval.

C. Fire Detectors

1. The fire detection system's heat and smoke detectors for all protected zones shall be operable except that one detector for a given protected zone may be inoperable for a period no greater than 30 days.

2. If specification 3.11.C.1 cannot be met, a patrolling fire watch will be established to ensure that each protected zone or area with inoperable detectors is checked at intervals no greater than one each hour.

4.11 FIRE PROTECTION SYSTEMS

C. Fire Detectors

1. All heat and smoke detectors shall be tested in accordance with industrial standards or other approved methods semiannually.

2. The non-Class A supervised detector circuitry for those detectors which provide alarm only will be tested once each month by actuating the detector at the end of the line or end of the branch such that the largest number of circuit conductors will be checked.

3.11 FIRE PROTECTION SYSTEMS

D. A roving fire watch will tour each area in which automatic fire suppression systems are to be installed (as described in the "Plan for Evaluation, Repair, and Return to Service of Browns Ferry Units 1 and 2," Section X) at intervals no greater than 2 hours. A keyclock recording type system shall be used to monitor the routes of the roving fire watch. The patrol will be discontinued as the automatic suppression systems are installed and made operable for each specified area.

4.11 FIRE PROTECTION SYSTEMS

3. The class A supervised detector alarm circuits will be tested once each two months at the local panels.

4. The circuits between the local panels in 4.11.C.3 and the main control room will be tested monthly.

5. Smoke detector sensitivity will be checked in accordance with manufacturer's instruction annually.

D. A monthly walk-through by the Safety Engineer will be made to visually inspect the plant fire protection system for signs of damage, deterioration, or abnormal conditions which could jeopardize proper operation of the system.

3.11 FIRE PROTECTION SYSTEMS

E. Fire Protection System Inspection

1. An independent fire protection and loss prevention inspection and audit shall be performed annually utilizing either qualified TVA personnel or an outside fire protection firm.

2. An inspection and audit by an outside qualified fire consultant will be performed at intervals no greater than 3 years. (The first inspection and audit will be during the period of June - September 1977.)

F. If it becomes necessary to breach a fire stop, an attendant shall be posted on each side of the open penetration until work is completed and the penetration is resealed.

G. The minimum in-plant fire protection organization and duties shall be as depicted in Figure 6.3-1.

4.11 FIRE PROTECTION SYSTEMS

E. Fire Protection Systems Inspection

Any inspection or audit will review and evaluate the effectiveness of fire prevention and protection by physical inspection of plant facilities, systems, and equipment as related to fire safety. Evaluations will be made of, but not necessarily limited to, the following:

Administrative control documentation, maintenance of fire related records, physical plant inspection, related historical research and application, and management interviews.

3.11 FIRE PROTECTION SYSTEMS

H. A minimum of fifteen air masks and thirty 500 cubic inch air cylinders shall be available at all times except that a time period of 48 hours following emergency use is allowed to permit recharging or replacing.

I. A continuous fire watch shall be stationed in the immediate vicinity where work involving open flame welding, or burning is in progress.

J. There shall be no use of open flame, welding, or burning in the cable spreading room unless the reactor is in the cold shutdown condition.

4.11 FIRE PROTECTION SYSTEMS

TABLE 3.11.A

FIRE PROTECTION SYSTEM HYDRAULIC REQUIREMENTS

Station	Flow Required (gpm)	Residual Pressure (psig)
1. Reactor Building Roof		
A. Valve 26-849	200	65
B. Valve 26-889	200	65
2. Refuel Floor		
A. Valve 26-835	75	70
B. Valve 26-843	75	70
C. Valve 26-870	75	70
D. Valve 26-865	75	70
E. Valve 26-876	75	70
F. Valve 26-888	75	70
G. Valve 26-898	75	70
3. Cable Tray Fixed Spray		
A. Unit 1 - Station I	300	70
B. Unit 1 - Station II	200	70
C. Unit 1 - Station III	180	65
D. Unit 2 - Station II	200	70
E. Unit 2 - Station III	200	70
F. Unit 3 - Station II	200	70
G. Unit 3 - Station III	265	75
H. Turbine Building	30	55
4. Diesel Generator Buildings		
A. Valve 26-1032	75	70
B. Valve 26-1069	75	70
5. Pump Intake Station		
A. Valve 26-578	75	70

TABLE 3.11.A

FIRE PROTECTION SYSTEM HYDRAULIC REQUIREMENTS

Station	Flow Required (gpm)	Residual Pressure (psig)
6. Control Bay		
A. Valve 26-1076	75	70
7. Yard Loop (1)		
A. Hydrant at valve 0-26-526	500	65
B. Hydrant at valve 0-26-530	500	65
8. Cooling Tower Loop		
A. Hydrant at valve 0-26-1023-6	500	65

Note (1) Yard hydrants and the cooling tower hydrant are to be tested using the longest path for flow.

3.11 BASES

The High Pressure Fire and CO_2 Fire Protection specifications are provided in order to meet the preestablished levels of operability during a fire in either or all of the three units. Requiring a patrolling fire watch with portable fire equipment if the automatic initiation is lost will provide (as does the automatic system) for early reporting and immediate fire fighting capability in the event of a fire occurrence.

The High pressure Fire Protection System is supplied by three pumps aligned to the high pressure fire header. The reactors may remain in operation for a period not to exceed 7 days if two pumps are out of service. If at least two pumps are not made operable in seven days or if all pumps are lost during this seven day period, the reactors will be placed in the cold shutdown condition within 24 hours.

For the areas of applicability, the fire protection water distribution system minimum capacity of 2664 gpm at 250' head at the fire pump discharge consists of the following design loads:

1.	Sprinkler System (0.30 gpm/ft²/4440 ft² area)	1332 gpm
2.	1 1/2" Hand Hose Lines	200 gpm
3.	Raw Service Water Load	1132 gpm
	TOTAL	2664 gpm

The CO_2 Fire Protection System is considered operable with a minimum of 8 1/2 tons (0.5 tank) CO_2 in storage for units 1 and 2; and a minimum of 3 tons (0.5 tank) CO_2 in storage for unit 3. An immediate and continuous fire watch in the cable spreading room or any diesel generator building area will be established if CO_2 fire protection is lost in this room and will continue until CO_2 fire protection is restored.

To assure close supervision of fire protection system activities, the removal from service of any component in either the High Pressure Fire System or the CO_2 Fire Protection System for any reason other than testing or emergency operations will require Plant Superintendent approval.

Early reporting and immediate fire fighting capability in the event of a fire occurrence will be provided (as with the automatic system) by requiring a patrolling fire watch if more than one detector for a given protected zone is inoperable.

A roving fire watch for areas in which automatic fire suppression systems are to be installed will provide additional interim fire protection for areas that have been determined to need additional protection.

The fire protection system is designed to supply the required flow and pressure to an individual load listed on Table 3.11.A while maintaining a design raw service water load of 1132 gpm.

4.11 BASES

Periodic testing of both the High Pressure Fire System and the CO_2 Fire Protection System will provide positive indication of their operability. If only one of the pumps supplying the High Pressure Fire System is operable, the pump that is operable will be checked immediately and daily thereafter to demonstrate operability. If the CO_2 Fire Protection System becomes inoperable in the cable spreading room, one 125-pound (or larger) fire extinguishere will be placed at each entrance to the cable spreading room.

Wet fire header flushing, spray header inspection for blockage, and nozzle inspection for blockage will prevent, detect, and remove buildup of sludge or other material to ensure continued operability. System flushes in conjunction with the semiannual addition of biocide to the Raw Cooling Water System will help prevent the growth of crustaceans which could reduce nozzle discharge.

Semiannual tests of heat and smoke detectors are in accordance with the NFPA code.

With the exception of continuous strip heat detectors panels, all non-class A supervised detector circuits which provide alarm only are hardwired through conduits and/or cable trays from the detector to the main control room alarm panels with no active components between. Non-class A circuits also actuate the HPCI water-fog system, the CO_2 system in the diesel generator buildings, and isolate ventilation in shutdown board rooms. The test frequency and methods specified are justified for the following reasons:

1. An analysis was made of worst-case fire detection circuits at Browns Ferry to determine the probability of no undetected failure of the circuits occurring between system test times as specified in the surveillance requirements. A circuit is defined as the wire connections and components that affect transmission of an alarm signal between the fire detectors and the control room annunciator. Three circuits were analyzed which were representative of an alarm-only circuit, a water-fog circuit, and a CO_2 circuit. The spreading room B smoke detector was selected as the worst-case alarm-only circuit because it had the largest number of wires and connections in a single circuit. The HPCI water-fog circuit was selected for analysis because it is the only water-fog circuit in the area of applicability for technical specifications. The Standby Diesel Generator Room A CO_2

circuit was selected because it contained 2 out of 3 detector logic, the most complicated CO_2 circuit logic. Calculations were based on failure rates for wires, connections, and circuit components as shown in Appendix III of WASH-1400. Failure rates were considered for the following circuit components:

1. Open circuit
2. Short to ground
3. Short to power
4. Timing motor failure to start
5. Relay failure to energize
6. Normally open contact failure to close
7. Normally open or normally closed contact short
8. Normally closed contact opening
9. Timing switch failure to transfer

The calculated probabilities (Pf) for no undetected failure of the circuits occurring were as follows, based on the specified test frequency.

AREA	TEST FREQUENCY	Pf
Spreading Room B	One Month	0.975287
HPCI Water Fog	Six Months	0.977175
Standby Diesel Gen Room A CO_2	Six Months	0.957595

The worst case of the three areas considered is Spreading Room B. The probability of undected failure is approximately 1/40, which means that one undetected failure will occur on the average every 40 months over an extended period of time and that the failure could exist up to one month. The frequency of testing is thus much greater than the frequency of failure and produces circuits with adequate reliability.

2. Circuits checks by initiation of end of the line or end of the branch detectors will more thoroughly test the parallel curcuits than testing on a rotating detector basis. This test is not a detector test, but is a test to simulate the effect of electrical supervision as defined in the NFPA code.*

3. Testing of circuits which actuate CO_2 , water, or ventilation systems requires disabling the automatic feature of the fire protection system for the area. A surveillance program which disabled these circuits monthly would significantly reduce the ability of these circuits to provide fire suppression.

*Ref: NFPA Code 72D-9, paragraph 1111, Code 72D-15, paragraph 1312 for definition of Class A systems, and Code 72A-18, Article 240.

4. Daily tests of annunciation lights and audible devices are performed as a routine operation function.

5. The CO_2 system manufacturer recommends semiannual testing of CO_2 system fire detection circuits.

Figure 6.3-1 describes the in-plant fire protection organization including the roving fire watch. In addition, other operating personnel periodically inspect the plant during their normal operating activities for fire hazards and other abnormal conditions.

Smoke detectors will be tested "in-place" using inert freon gas applied by a pyrotronics type applicator which is accepted throughout the industrial fire protection industry for testing products of combustion detectors or by use of the MSA chemical smoke generators. At the present time the manufacturers have only approved the use of "punk" for creating smoke. TVA will not use "punk" for testing smoke detectors.

5.0 MAJOR DESIGN FEATURES

5.1 SITE FEATURES

Browns Ferry unit 1 is 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 core shall consist of 764 fuel assemblies of 49 fuel rods each.

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 as 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 fuel in the new-fuel storage facility shall be such that k_{eff}, for dry conditions, is less than 0.90 and flooded is less than 0.95 (Section 10.2 of FSAR).

B. The k_{eff} of the spent fuel storage pool shall be less than or equal to 0.90 for normal conditions and 0.95 for abnormal conditions (Sections 10.3 of the FSAR).

5.6 SEISMIC DESIGN

The station class I structures and systems have been designed to withstand a design basis earthquake with ground acceleration of 0.2g. The operational basis earthquake used in the plant design assumed a ground acceleration of 0.1g (see Section 2.5 of the FSAR).

6.0 ADMINISTRATIVE CONTROLS

6.1 Organization

A. The plant superintendent has on-site responsibility for the safe operation of the facility and shall report to the Chief, Nuclear Generation Branch. In the absence of the plant superintendent, the assistant superintendnet will assume his responsibilities.

B. The portion of TVA management which relates to the operation of the plant is shown in Figure 6.1-1.

C. The functional organization for the operation of the station shall be as shown in Figure 6.1-2.

D. Shift manning requirements shall, as a minimum, be as described in section 6.8.

E. Qualifications of the Browns Ferry Nuclear Plant management and operating staff shall meet the minimum acceptable levels as described in ANSI - N18.1, Selection and Training of Nuclear Power Plant Personnel, dated March 8, 1971.

F. Retraining and replacement training of station personnel shall be in accordance with ANSI - N18.1, Selection and Training of Nuclear Power Plant Personnel, dated March 8, 1971. The minimum frequency of the retraining program shall be every two years.

G. An Industrial Security Program shall be maintained for the life of the plant.

H. Responsibilities of a post-fire overall restoration coordinator will consist of duties as described in section 6.9.

I. The Safety Engineer shall have the following qualifications:

a. Must have a sound understanding and thorough technical knowledge of safety and fire protection practices, procedures, standards, and other codes relating to electrical utility operations. Must be able to read and understand engineering drawings. Must possess an analytical ability for problem solving and data analysis. Must be able to communicate well both orally and in writing and must be able to write investigative reports and prepare written procedures. Must have the ability to secure the cooperation of management, employees and groups in the implementation of safety programs. Must be able to conduct safety presentations for supervisors and employees.

b. Should have experience in safety engineering work at this level or have 3 years experience in safety and/or fire protection engineering. It is desirable that the incumbent be a graduate of an accredited college or university with a degree in inductrial, mechanical, electrical, or safety engineering or fire protection engineering.

6.0 ADMINISTRATIVE CONTROLS

6.2 Review and Audit

The Manager of Power is responsible for the safe operation of all TVA power plants, including the Browns Ferry Nuclear Plant. The functional organization for Review and Audit is shown in Figure 6.2-1.

Organizational units for the review of facility operation shall be constituted and have the responsibilities and authorities listed below.

A. Nuclear Safety Review Board (NSRB)

1. Membership

The NSRB shall consist of a chairman and at least five other members appointed or approved by the Manager of Power. A majority of the members shall be independent of the Division of Power Production. The qualifications of members shall meet the requirements of ANSI Standard N18.7-1972. Membership shall include at least one outside consultant and representatives of the following TVA organizations: Office of Engineering Design and Construction; Division of Environmental Planning; Division of Power Production; Division of Power Resource Planning. An alternate chairman may be designated by the chairman or, in his absence or incapacity, may be selected by the NSRB. The NSRB chairman shall appoint a secretary.

2. Minimum Meeting Frequency

The NSRB shall meet at least quarterly and at more frequent intervals at the call of the chairman, as required.

3. Quorum

A quorum shall consist of four members, a minority of which shall be from the Division of Power Production.

4. Responsibilities

a. Review proposed tests and experiments, and their results, when such tests or experiments may constitute an unreviewed safety question as defined in Section 50.59, Part 50, Title 10, Code of Federal Regulations.

b. Review proposed changes to equipment, systems or procedures, which are described in the Final Safety Analysis Report or which may involve an unreviewed safety question, as defined in Section 50.59, Part 50, Title 10, Code of Federal Regulations, or which are referred by the operating organization.

c. Review proposed changes to Technical Specifications or licenses.

d. Review violations of applicable statutes, codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having safety significance.

e. Review signficant operating abnormalities or deviations from normal and expected performance of plant equipment.

f. Review reportable occurrences, as defined in the Technical Specifications.

g. Review information received indicating that there may be an unanticipated deficiency in some aspect of design or operation of safety-related systems or components.

h. Review the reports of annual audits of plant operation to verify that operation complies with the terms, conditions and intent of any license, permit, or other applicable regulations.

i. Review the minutes of Plant Operations Review Committee meetings to determine if matters considered by that committee involve unreviewed or unresolved safety questions.

5. Authority

The Nuclear Safety Review Board shall be advisory to the Manager of Power in matters relating to nuclear plant safety.

The Nuclear Safety Review Board shall have access to all TVA nuclear facilities, as well as design, construction, and operating records as necessary to perform it assigned functions.

Members have access to advice and services of technical specialists within their respective organizations and outside consulting services are available as required through contractual arrangements.

6. Records

The chairman shall prepare a final copy of the minutes and forward them to the Manager of Power.

A summary of the more significant discussions and conclusions of the NSRB will be transmitted along with the final minutes.

7. Charter

A written charter delineating the establishment, composition, and mission of the NSRB and the dissemination of NSRB minutes and reports shall be maintained; this may be amended as required. The charter shall identify the responsibility and authority of the NSRB in conducting reviews, including responsibility to identify problems and to recommend solutions to the Manager of Power.

B. Plant Operations Review Committee (PORC)

1. Membership

The PORC shall consist of the plant superintendent, assistant plant superintendent, maintenance supervisor, health physics supervisor, operations supervisor, power plant results supervisor, and QA staff supervisor. An assistant plant supervisor may serve as an alternate committee member when his supervisor is absent.

The plant superintendent will serve as chairman of the PORC. The assistant plant superintendent will serve as chairman in the absence of the plant superintendent.

2. Meeting Frequency

The PORC shall meet at regular monthly intervals and for special meetings as called by the chairman or as requested by individual members.

3. Quorum

Superintendent or assistant superintendent, plus four of the five other members, or their alternate, will constitute a quorum. A member will be considered present if he is in telephone communication with the committee.

4. Duties and Responsibilities

The PORC serves in an advisory capacity to the plant superintendent and as an investigating and reporting body to the Nuclear Safety Review Board in matters related to safety in plant operations. The plant superintendent has the final responsibility in determining the matters that should be referred to the Nuclear Safety Review Board.

The responsibility of the committee will include:

a. Review all standard and emergency operating and maintenance instructions and any proposed revisions thereto, with principal attention to provisions for safe operation.

b. Review porposed changes to the Technical Specifications.

c. Review proposed changes to equipment or systems having safety significance, or which may constitute "an unreviewed safety question," pursuant to 10 CFR 50.59.

d. Investigate reported or suspected incidents involving safety questions, violations of the Technical Specifications, and violations of plant instructions pertinent to nuclear safety.

e. Review reportable occurrences, unusual events, operating anomalies and abnormal performance of plant equipment.

f. Maintain a general surveillance of plant activities to identify possible safety hazards.

g. Review plans for special fuel handling, plant maintenance, operations, and tests or experiements which may involve special safety considerations, and the results thereof, where applicable.

h. Review adequacy of quality assurance program and recommend any appropriate changes.

i. Review implementating procedures of the Radiological Emergency Plan and the Industrial Security Program on an annual basis.

j. Review adequacy of employee training programs and recommend change.

5. Authority

The PORC shall be advisory to the plant superintendent.

6. Records

Minutes shall be kept for all PORC meetings with copies sent to Director, Power Production; Chief, Nuclear Generation Branch; Chairman, NSRB.

7. Procedures

Written administrative procedures for committee operation shall be prepared and maintained describing the method for submission and content of presentations to the committee, review and approval by members of committee actions, dissemination of minutes, agenda and scheduling of meetings.

C. Quality Assurance and Audit Staff

The Office of Power Quality Assurance and Audit Staff (QA&AS) shall formally audit operation of the nuclear plant. Audits of selected aspects of plant operations shall be conducted on a frequency commensurate with their safety significance and in such a manner as to assure that an audit of safety-related activities is completed within a period of two years.

The audits shall be performed in accordance with appropriate written instructions or procedures and should include verification of compliance with internal rules, procedures (for example, normal off/normal, emergency, operating, maintenance, surveillance, test, security, and radiation control procedures and the emergency plan), regulations, and license provisions; training, qualification, and performance of operating staff; and corrective actions following reportable occurrences.

6.3 Procedures

A. Detailed written procedures, including applicable check-off lists covering items listed below shall be prepared, approved and adhered to.

1. Normal startup, operation and shutdown of the reactor and of all systems and components involving nuclear safety of the facility.

2. Refueling operations.

3. Actions to be taken to correct specific and foreseen potential malfunctions of systems or components, including responses to alarms, suspected primary system leaks and abnormal reactivity changes.

4. Emergency conditions involving potential or actual release of Radioactivity.

5. Preventive or corrective maintenance operations which could have an effect on the safety of the reactor.

6. Surveillance and testing requirements.

7. Radiation control procedures.

8. Radiological Emergency Plan implementing procedures.

9. Plant security program implementing procedures.

10. Fire protection and prevention procedures.

B. Written procedures pertaining to those items listed above shall be reviewed by PORC and approved by the plant superintendent prior to implementation. Temporary changes to a procedures 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 except that temporary changes to those items listed above except item 5 require the additional approval of a member of the plant staff who holds a Senior Reactor Operator license on the unit affected. Such changes shall be documented and subsequently reviewed by PORC and approved by the plant superintendent.

C. Drills on actions to be taken under emergency conditions involving release of radioactivity are specified in the radiological emergency plan and shall be conducted annually. Annual drills shall also be conducted on the actions to be taken following failures of safety related systems or components.

D. Radiation Control Procedures

Radiation Control Procedures shall be maintained and made available to all station personnel. These procedures shall show permissible radiation exposure and shall be consistent with the requirements of 10 CFR 20. This radiation protection program shall be organized to meet the requirements of 10 CFR 20 except in lieu of the "control device" or "alarm signal" required by paragraph 20.203(c)(2) of 10 CFR 20:

1. Each High Radiation Area in which the intensity of radiation is greater than 100 mrem/hr but less than 1,000 mrem/hr shall be barricaded and conspicuously posted as a High Radiation Area, and entrance thereto shall be controlled by issuance of a special work permit. Any individual or group of individuals permitted to enter such areas shall be provided with a radiation monitoring device which continuously indicates the radiation dose rate in the area.

2. Each High Radiation Area in which the intensity of radiation is greater than 1,000 mrem/hr shall be subject to the provisions of (a) above; and, in addition, locked doors shall be provided to prevent unauthorized entry into such areas, and the keys shall be maintained under administrative control of the shift engineer on duty.

3. Pursuant to 10 CFR 20.103 (c)(1) and (3), allowance can be made for the use of respiratory protective equipment in conjunction with activities authorized by the operating license for this plant in determining whether individuals in restricted areas are exposed to concentrations in excess of the limits specified in Appendix B, Table I, Column 1, of 10 CFR 20, subject to the following condition and limitations:

   a. The limits provided in section 20.103(a) and (b) are not exceeded.

b. If the radioactive material is of such form that intake through the skin or other additional route is likely, individual exposures to radioactive material shall be controlled so that the radioactive content of any critical organ from all routes of intake averaged over 7 consecutive days does not exceed that which would result from inhaling such radioactive material for 40 hours at the pertinent concentration values provided in Appendix B, Tab,e I, Column 1 of 10 CFR 20.

c. For radioactive materials designed "sub" in the "Isotope" column of Appendix B, Table I, Column 1 of 10 CFR 20, the concentration value specified is based upon exposure to the material as an external radiation source. Individual exposures to these materials shall be accounted for as part of the limitation on individual dose in 20.101. These materials shall be subject to applicable process and other engineering controls.

4. In all operations in which adequate limitation of the inhalation of radioactive material by the use of process or other engineering controls is impracticable, the licensee may permit an individual in a restricted area to use respiratory protective equipment to limit the inhalation of airborne radioactive material, provided:

a. The limits specified in paragraph 1 above are not exceeded.

b. Respiratory protective equipment is selected and used so that the peak concentrations of airborne radioactive material inhaled by an individual wearing the equipment does not exceed the pertinent concentration values specified in Appendix B, Table I, Column 1, of 10 CFR 20. For the purposes of this subparagrpah, the concentration of radioactive material that is inhaled when respirators are worn may be determined by dividing the ambient airborne concentration by the protection factor specified in Table 16.3.A, appended to this specification for the respirator protective equipment worn. If the intake or radioactivity is later determined by other measurements to have been different than that

initially estimated, the later quantity shall be used in evaluating the exposures.

c. The licensee advises each respirator user that he may leave the area at any time for relief from respirator use in case of equipment malfunction, significant physical or psychological discomfort, or any other condition that might cause reduction in the protection afforded the wearer.

d. The licensee maintains a respiratory protective program adequate to assure that the requirements above are met and incorporates practices for respiratory protection consistent with those recommended by the American National Standards Institute (ANSI-Z88.2-1969). Such a program shall include:

(1) Air sampling and other surveys sufficient to identify the hazard, to evaluate individual exposures, and to permit proper selection of respiratory protective equipment.

(2) Written procedures to assure proper selection, supervision, and training of personnel using such protective equipment.

(3) Written procedures to assure the adequate fitting of respirators; and the testing of respiratory protective equipment for operability immediately prior to use.

(4) Written procedures for maintenance to assure full effectiveness of respiratory protective equipment, including issuance, cleaning and decontamination, inspection, repair, and storage.

(5) Written opertional and administrative procedures for proper use of respiratory protective equipment including provisions for planned limitations on working times as necessitated by operational conditions.

(6) Bioassays and/or whole body counts of individuals (an other surveys, as

appropraite) to evaluate individual exposures and to assess protection actually provided.

e. The licensee uses equipment approved by the U.S. Bureau of Mines under its appropriate approval schedules as set forth in Table 6.3.A below. Equipment not approved under U.S. Bureau of Mines Approval Schedules may be used only if the licensee has evaluated the equipment and can demonstrate by testing, or on the basis of reliable test information, that the material and performance characteristics of the equipment are at least equal to those afforded by U.S. Bureau of Mines approved equipment of the same type, as specified in Table 6.3.A below.

f. Unless otherwise authorized by the Commission, the licensee does not assign protection factors in excess of those specified in Table 6.3.A below in selecting and using respiratory protective equipment.

5. These specifications with respect to the provision of 20.103 shall be superseded by adoption of proposed changes to 10 CFR 20, section 20.103, which would make this specification unnecessary.

TABLE 6.3.A

PROTECTION FACTORS FOR RESPIRATORS

DESCRIPTION	MODES 1/	PROTECTION FACTORS 2/ PARTICULATES AND VAPORS AND GASES EXCEPT TRITIUM OXIDE 3/	GUIDES TO SELECTION OF EQUIPMENT BUREAU OF MINES APPROVAL SCHEDULES* FOR EQUIPMENT CAPABLE OF PROVIDING AT LEAST EQUIVALENT PROTECTION FACTORS *or schedule superseding for equipment of type listed
I. AIR-PURIFYING RESPIRATORS			
Facepiece, half-mask 4/ 7/	NP	5	30 CFR Part 11 Subpart K
Facepiece, full 7/	NP	100	30 CFR Part 11 Subpart K
II. ATMOSPHERE-SUPPLYING Respirator			
1. Airline Respirator			
Facepiece, half-mask	CF	100	30 CFR Part 11 Subpart J
Facepiece, full	CF	1,000	30 CFR Part 11 Subpart J
Facepiece, full 7/	D	100	30 CFR Part 11 Subpart J
Facepiece, full	PD	1,000	30 CFR Part 11 Subpart J
Hood	CF	5/	30 CFR Part 11 Subpart J
Suit	CF	5/	6/
2. Self-contained breathing apparatus (SCBA)			
Facepiece, full 7/	D	100	30 CFR Part 11 Subpart H
Facepiece, full	PD	1,000	30 CFR Part 11 Subpart H
Facepiece, full	R	1,000	30 CFR Part 11 Subpart H
III. COMBINATION RESPIRATOR			
Any combination of air-purifying and atmosphere-supplying respirator		Protection factor for type and mode of operation as listed above	30 CFR Part 11 §11.63(b)

1/, 2/, 3/, 4/, 5/, 6/, 7/, (These notes are on the following pages)

1/ See the following symbols:

CF: continuous flow
D : demand
NP: negative pressure (i.e., negative phase during inhalation)
PD: pressure demand (i.e., always positive pressure)
R : recirculating (closed circuit)

2/ (a) For purposes of this specification the protection factor is a measure of the degree of protection afforded by a respirator, defined as the ratio of the concentration of airborne radioactive material outside the respiratory protective equipment to that inside the equipment (usually inside the facepiece) under conditions of use. It is applied to the ambient airborne concentration to estimate the concentration inhaled by the wearer according to the following formula:

$$\text{Concentration Inhaled} = \frac{\text{Ambient Airborne Concentration}}{\text{Protection Factor}}$$

(b) The protection factors apply:

(i) only for trained individuals wearing properly fitted respirators used and maintained under supervision in a well-planned respiratory protective program.

(ii) for air-purifying respirators only when high efficiency (above 99.9% removal efficiency by U.S. Bureau of Mines type dioctyl phthalate (DOP) test) particulate filters and/or sorbents appropriate to the hazard are used in atmospheres not deficient in oxygen.

(iii) for atmosphere-supplying respirators only when supplied with adequate respirable air.

3/ Excluding radioactive contaminants that present an adsorption or submersion hazard. For tritium oxide approximately half of the intake occurs by adsorption through the skin so that an overall protection factor of not more than approximately 2 is appropriate when atmosphere-supplying respirators are used to protect against tritium oxide. Air-purifying respirators are not recommended for use against tritium oxide. See also foot note 5/, below, concerning supplied-air suits and hoods.

4/ Under chin type only. Not recommended for use where it might be possible for the ambient airborne concentration to reach

instantaneous values greater than 5 times the pertinent values in Appendix B, Table I, Column 1 of 10 CFR, Part 20.

5/ Appropriate protection factors must be determined taking account of the design of the suit or hood and its permeability to the containment under conditions of use. No protection factor greater than 1,000 shall be used except as authorized by the Commission.

6/ No approval schedules currently available for this equipment. Equipment must be evaluated by testing or on basis of available test information.

7/ Only for shaven faces.

Note 1: Protection factors for respirators, as may be approved by the U.S. Bureau of Mines and/or NIOSH according to approval schedules for respirators to protect against airborne radionuclides, may be used to the extent that they do not exceed the protection factors listed in this table. The protection factors in this table may not be appropriate to circumstances where chemical or other respiratory hazards exist in addition to radioactive hazards. The selection and use of respirators for such circumstances should take into account approvals of the U.S. Bureau of Mines and/or NIOSH in accordance with its applicable schedules.

Note 2: Radioactive contaminants for which the concentration values in Appendix B, Table I, of this part are based on internal dose due to inhalation may, in addition, present external exposure hazards at higher concentrations. Under such circumstances, limitations on occupancy may have to be governed by external dose limits.

6.4 Actions to be Taken in the Event of a Reportable Occurrence in Plant Operation (Ref. Section 6.7)

A. Any reportable occurrence shall be promptly reported to the Chief, Nuclear Generation Branch and shall be promptly reviewed by PORC. This committee shall prepare a separate report for each reportable occurrence. This report shall include an evaluation of the cause of the occurrence and recommendations for appropriate action to prevent or reduce the probability of a repetition of the occurrence.

B. Copies of all such reports shall be submitted to the Chief, Nuclear Generation Branch, the Manager of Power, the Division of Power Resource Planning, and the Chairman of the NSRB for their review.

C. The plant superintendent shall notify the NRC as specified in Specification 6.7 of the circumstances of any reportable occurrence.

6.5 Action to be Taken in the Event a Safety Limit is Exceeded

If a safety limit is exceeded, the reactor shall be shut down and reactor operation shall not be resumed until authorized by the NRC. A prompt report shall be made to the Chief, Nuclear Generation Branch and the Chairman of the NSRB. A complete analysis of the circumstances leading up to and resulting from the situation, together with recommendations to prevent a recurrence, shall be prepared by the PORC. This report shall be submitted to the Chief, Nuclear Generation Branch, the Manager of Power, the Division of Power Resource Planning, and the NSRB. Notification of such occurrences will be made to the NRC by the plant superintendent within 24 hours.

6.6 Station Operating Records

A. Records and/or logs shall be kept in a manner convenient for review as indicated below:

1. All normal plant operation including such items as power level, fuel exposure, and shutdowns

2. Principal maintenance activities

3. Reportable occurrences

4. Checks, inspections, tests, and calibrations of components and systems, including such diverse items as source leakage

5. Reviews of changes made to the procedures or equipment or reviews of tests and experiements to comply with 10 CFR 50.59

6. Radioactive shipments

7. Test results, in units of microcuries, for leak tests performed pursuant to Specification 3.8.E

8. Record of annual physical inventory verifying accountability of sources on record

9. Gaseous and liquid radioactive waste released to the environs

10. Off-site environmental monitoring surveys

11. Fuel inventories and transfers

12. Plant radiation and contamination surveys

13. Radiation exposures for all plant personnel

14. Updated, corrected, and as-built drawings of the plant

15. Reactor coolant system inservice inspection

16. Minutes of meetings of the Nuclear Safety Review Board

17. Design fatigue usage evaluation

    a. Monitoring, recording, evaluating, and reporting requirements contained in 17.b, below will be met for various portions of the reactor coolant pressure boundary (RCPB) for which detailed fatigue usage evaluation per the ASME Boiler and Pressure Vessel Code Section III was performed[1] for the conditions defined in the design specification. In this

1. See paragraph N-415.2, ASME Section III, 1965 Edition.

plant, the applicable codes required fatigue usage evaluation for the reactor pressure vessel only. The locations to be monitored shall be:

1. The feedwater nozzles

2. The shell at or near the waterline

3. The flange studs

b. Recording, Evaluating, and Reporting

(1) Transients that occur during plant operations will be reviewed and a cumulative fatigue usage factor determined.

(2) For transients which are more severe than the transients evaluated in the stress report, code fatigue usage calculations will be made and tabulated separately.

(3) In the annual Operating Report, the fatigue usage factor determined for the transients defined in (1) and (2) above shall be added and a cumulative fatigue usage factor to date shall be listed. When the cumulative usage factor reaches a value of 1.0, an inservice inspection shall be included for the specific location at the next scheduled inspection (3-1/3-year interval) period and 3-1/3-year intervals thereafter, and a subsequent evaluation performed in accordance with the rules of ASME Section XI Code if any flaw indications are detected. The results of the evaluation shall be submitted in a Special Report (Section 6.7.3) for review by the Commission.

B. Except where covered by applicable regulations, items 1 through 8 above shall be retained for a period of at least 5 years and items 9 through 17 shall be retained for the life of the plant. A complete inventory of radioactive materials in possession shall be maintained current at all times.

6.7 Reporting Requirements

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following identified reports shall be submitted to the Director of the appropriate Regional Office of Inspection and Enforcement unless otherwise noted.

1. Routine Reports

   a. Startup Report. A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall address each of the tests identified in the FSAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

      Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commerical power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

   b. Annual Operating Report.[1] Routine operating reports covering the operation of the unit during the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following intial criticality.

The annual operating reports made by licensees shall provide a comprehensive summary of the operating experience gained during the year, even though some repetition of previously reported information may be involved. References in the annual operating report to previously submitted reports shall be clear.

Each annual operating report shall include:

(1) A narrative summary of operating experience during the report period relating to safe operation of the facility, including safety-related maintanance not covered in item 1.b.(2)(e) below.

(2) For each outage or forced reduction in power[2] of over twenty percent of design power level where the reduction extends for greater than four hours:

(a) the proximate cause and the system and major component involved (if the outage or forced reduction in power involved equipment malfunction);

(b) A brief discussion of (or reference to reports of) any reportable occurrences pertaining to the outage of power reduction;

(c) corrective action taken to reduce the probability of recurrence, if appropriate;

(d) operating time lost as a result of the outage or power reduction (for scheduled or forced outages,[3] use the generator off-line hours; for forced reductions in power, use the approximate duration of operation at reduced power);

(e) a description of major safety-related corrective maintenance performed during the outage or power reduction, including the system and component involved and identification of the critical path activity dictating the length of the outage or power reduction; and

(f) a report of any single release of radioactivity or radiation exposure specifically associated with the outage which accounts for more than 10% of the allowable annual values.

(3) A tabulation on an annual basis of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man rem exposure according to work and job functions, e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, or film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources shall be assigned to specific major work functions.

(4) Indications of failed fuel resulting from irradiated fuel examinations, including eddy current tests, ultrasonic tests, or visual examinations completed during the report period.

c. Monthly Operati ng Report. Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis to the Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the appropriate Regional Office, to be submitted no later than the tenth of each month following the calendar month covered by the report.

2. Reportable Occurrences

Reportable occurrences, including corrective actions and measures to prevent reoccurrence, shall be reported to the NRC. Supplemental reports may be required to fully describe final resolution of occurrence. In case of corrected or supplemental reports, a licensee event report shall be completed and reference shall be made to the original report date.

a. Prompt Notification With Written Followup. The types of events listed below shall be reported as expeditiously as possible, but within 24 hours by telephone and confirmed by telegraph, mailgram, or facsimile transmission to the Director of the appropriate Regional Office, or his designate no later than the first working day following the event, with a written followup report within two weeks. The written followup report shall include, as a minimum, a completed copy of a licensee event report form. Information provided on the licensee event report form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

(1) Failure of the reactor protection system or other systems subject to limiting safety system settings to initiate the required protective function by the time a monitored parameter reaches the setpoint specified as the limiting safety system setting in the technical specifications or failure to complete the required protective function.

Note: Instrument drift discovered as a result of testing need not be reported under this item but may be reportable under items 2.a(5), 2.a(6), or 2.b(1) below.

(2) Operation of the unit or affected systems when any parameter or operation subject to a limiting condition is less conservative than the least conservative aspect of the limiting condition for operation established in the technical specifications.

Note: If specified action is taken when a system is found to be operating between the most conservative and the least conservative aspects of a limiting condition for operation listed in the technical specifications, the limiting condition for operation is not considered to have been violated and need not be reported under this item but it may be reportable under item 2.b(2) below.

(3) Abnormal degradation discovered in fuel cladding, reactor coolant pressure boundary, or primary containment.

Note: Leakage of valve packing or gaskets within the limits for identified leakage set forth in technical specifications need not be reported under this item.

(4) Reactivity anomalies, involving disagreement with the predicted value of reactivity balance under steady state conditions during power operation, greater than or equal to 1% $\Delta k/k$; a calculated reactivity balance indicating a shutdown margin less conservative than specified in the technical specifications; short-term reactivity increases that corresopond to a reactor period of less than 5 seconds or, if sub-critical, an unplanned reactivity insertion of more than 0.5% $\Delta k/k$; or occurrence of any unplanned criticality.

(5) Failure or malfunction of one or more components which prevent or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the SAR.

(6) Personnel error or procedural inadequacy which prevents or could prevent, by itself, the fulfillment of the functional requirements of systems required to cope with accidents analyzed in the SAR.

Note: For items 2.a(5) and 2.a(6) reduced redundancy that does not result in a loss of system function need not be reported under this section but may be reportable under items 2.b(2) and 2.b(3) below.

(7) Conditions arising from natural or man-made events that, as a direct result of the event require plant shutdown, operation of safety systems, or other protective measures required by technical specifications.

(8) Errors discovered in the transient or accident analyses or in the methods used for such analyses as described in the safety analysis report or in the bases for the technical specifications that have or could have permitted reactor operation in a manner less conservative than assumed in the analyses.

(9) Performance of structures, systems, or components that requires remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the safety analysis report or technical specifications bases; or discovery during plant life of conditions not specifically considered in the safety analysis report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition.

Note: This item is intended to provide for reporting of potentially generic problems.

b. Thirty-Day Written Reports. The reportable occurrences discussed below shall be the subject of written reports to the Director of the appropriate Regional Office within thirty days of occurrence of the event. The written report shall include, as a minimum, a completed copy of a licensee event report form. Information provided on the licensee event report form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

(1) Reactor protection system or engineered safety feature instrument settings which are found to be less conservative than those established by the technical specifications but which do not prevent the fulfillment of the functional requirements of affected systems.

(2) Conditions leading to operation in a degraded mode permitted by a limiting condition for operation or plant shutdown required by a limiting condition for operation.

Note: Routine surveillance testing, instrument calibration, or preventative maintenance which require system configurations as described in items 2.b.(1) and 2.b.(2) need not be reported except where test results themselves reveal a degraded mode as described above.

(3) Observed inadequacies in the implementation of administrative or procedural controls which

treaten to cause reduction of degree of redundancy provided in reactor protection systems or engineered safety feature systems.

(4) Abnormal degradation of systems other than those specified in item 2.a(3) above designed to contain radioactive material resulting from the fission process.

Note: Sealed sources or calibration sources are not included under this item. Leakage of valve packing or gaskets within the limits for identified leakage set forth in technical specifications need not be reported under this item.

3. Unique Reporting Requirements

A. Radioactive Effluent Release Report

A report on the radioactive discharges released from the site during the previous 6 months of operation shall be submitted to the Director of the Regional Office of Inspection and Enforcement within 60 days after January 1 and July 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents released and solid waste shipped from the plant as delineated in Regulatory Guide 1.21, Revision 1, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," with data summarized on a quarterly basis following the format of Appendix B thereof.

The report shall include a summary of the meteorological conditions concurrent with the release of gaseous effluents during each quarter as outlined in Regulatory Guide 1.21, Revision 1, with data summarized on a quarterly basis following the format of Appendix B thereof. Calculated offsite dose to humans resulting from the release of effluents and their subsequent dispersion in the atmosphere shall be reported as recommended in Regulatory Guide 1.21, Revision 1.

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	3.2.J.3	Within 10 days after 30 days of inoperability

FOOTNOTES

1. A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

2. The term "forced reduction in power" is normally defined in the electric power industry as the occurrence of a component failure or other condition which requires that the load on the unit be reduced for corrective action immediately or up to and including the very next weekend. Note that routine preventive maintenance, surveillance, and calibration activities requiring power reductions are not covered by this section.

3. The term "forced outage" is normally defined in the electric power industry as the occurrence of a component failure or other condition which requires that the unit be removed from service for corrective action immediately or up to and including the very next weekend.

4. This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

5. Each integrated leak rate test of the secondary containment shall be the subject of a summary technical report. This report should include data on the wind speed, wind direction, outside and inside temperatures during the test, concurrent reactor building pressure, and emergency ventilation flow rate. The report shall also include analyses and interpretations of those data which demonstrate compliance with the specified leak rate limits.

6.0 ADMINISTRATIVE CONTROLS

6.8 Minimum Plant Staffing

The minimum plant staffing for monitoring and conduct of operations is as follows.

1. A licensed senior operator shall be present at the site at all times when there is fuel in the reactor.

2. A licensed operator shall be in the control room whenever there is fuel in the reactor.

3. A licensed senior operator shall be in direct charge of a reactor refueling operation; i.e., able to devote full time to the refueling operation.

4. A health physics technician shall be present at the facility at all times there is fuel in the reactor.

5. Two licensed operators shall be in the control room during any cold startups, while shutting down the reactor, and during recovery from unit trip.

6. Either the plant superintendent or the assistant plant superintendent shall have acquired the experience and training normally required for examination by the NRC for a Senior Reactor Operator's License, whether or not the examination is taken. In addition, either the operations supervisor or the assistant operations supervisor shall have an SRO license.

6.9 Overall Restoration Coordinator

An overall restoration coordinator has been appointed and designated the responsibility of overseeing the entire restoration activity of units 1 and 2. The restoration activity is a result of the cable fire which took place on March 22, 1975.

Responsibilities of the overall Browns Ferry units 1 and 2 restoration coordinator include the following:

1. Principal coordinator for all design, construction, and operational activities relative to restoration of units 1 and 2.

2. Review and approval of all documents submitted by TVA to NRC in connection with restoration, fire protection and prevention improvements, and return to service of units 1 and 2.

3. Responsible for overall planning, establishment, and maintenance of critical path schedule for restoration of units 1 and 2.

4. Coordination and approval of TVA's overall efforts in fire protection and prevention improvements, including design and installation of new systems and changes necessary in fire fighting methods and techniques.

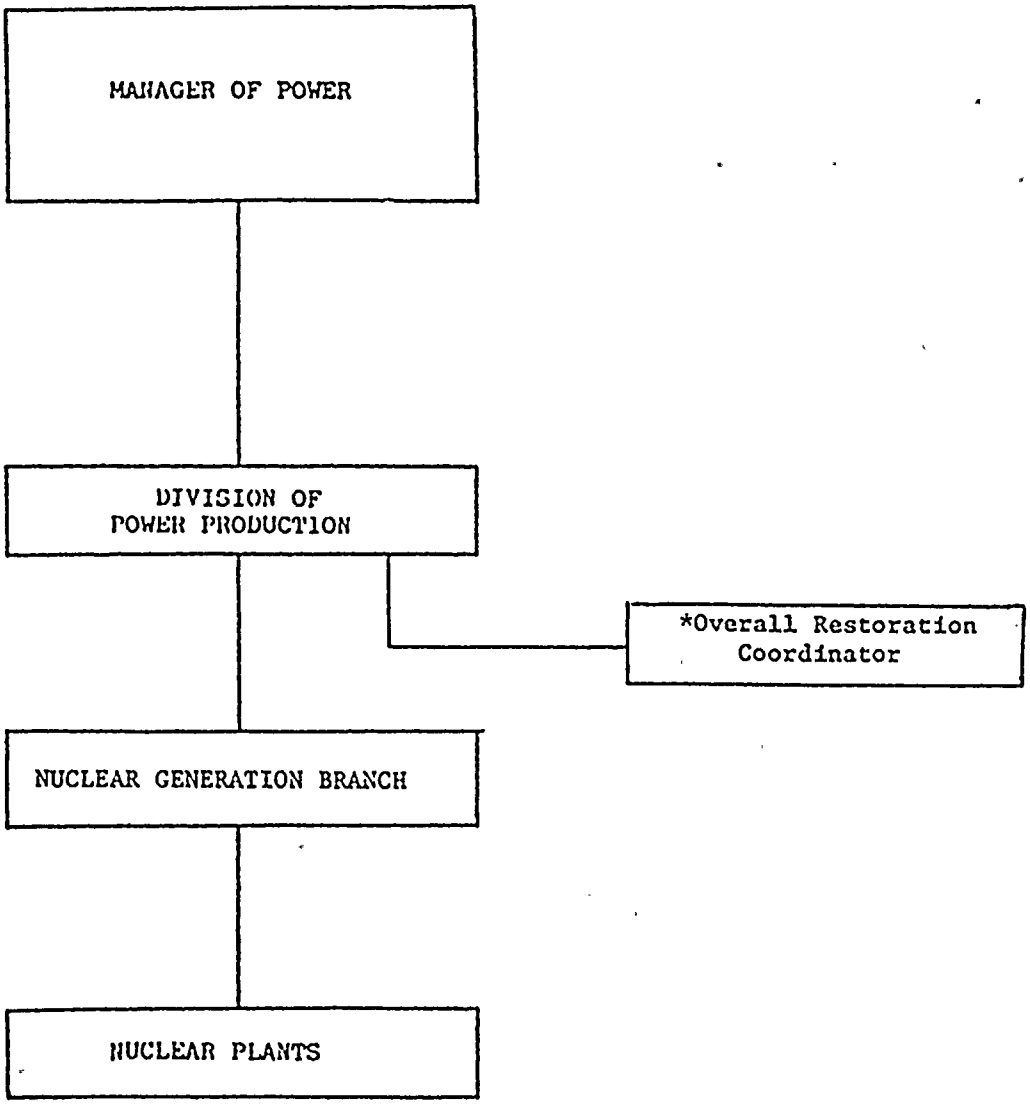
Table 6.8.A

Minimum Shift Crew Requirements Shift Position	Units in Operation 1	 2	 3	Type of License
Shift Engineers (SE)	1	1	1	SRO
Assistant Shift Engineers (ASE)	0	1	2	SRO
Licensed Reactor Operator[1]	1	1	1	RO
Unit Operators (UO)	1	2	3	RO
Assistant Unit Operators (AUO)	4	4	6	None
Health Physics Technician	1	1	1	None
Minimum Shift Crew	8	10	14	

Notes: SRO - Senior Reactor Operator
RO - Reactor Operator

Note for Table 6.8.A

1. This position is normally filled by an assistant shift engineer, but as a minimum it may be filled by a licensed reactor operator. When the incumbent is not a senior reactor operator, he shall not be assigned duties requiring him to direct licensed activities of reactor operators.

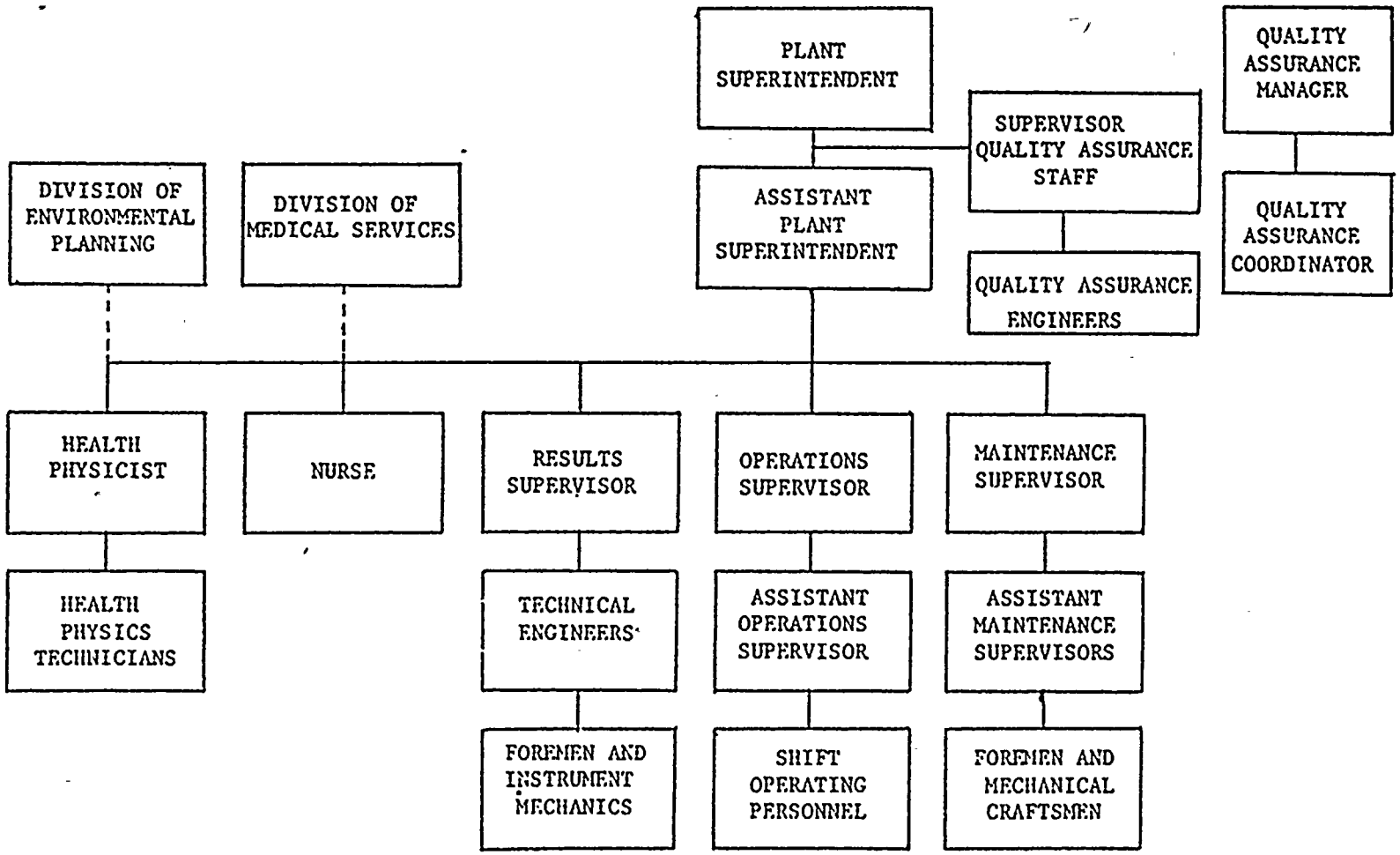


* This is a temporary position which will only continue until all restoration commitments have been completed.

BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

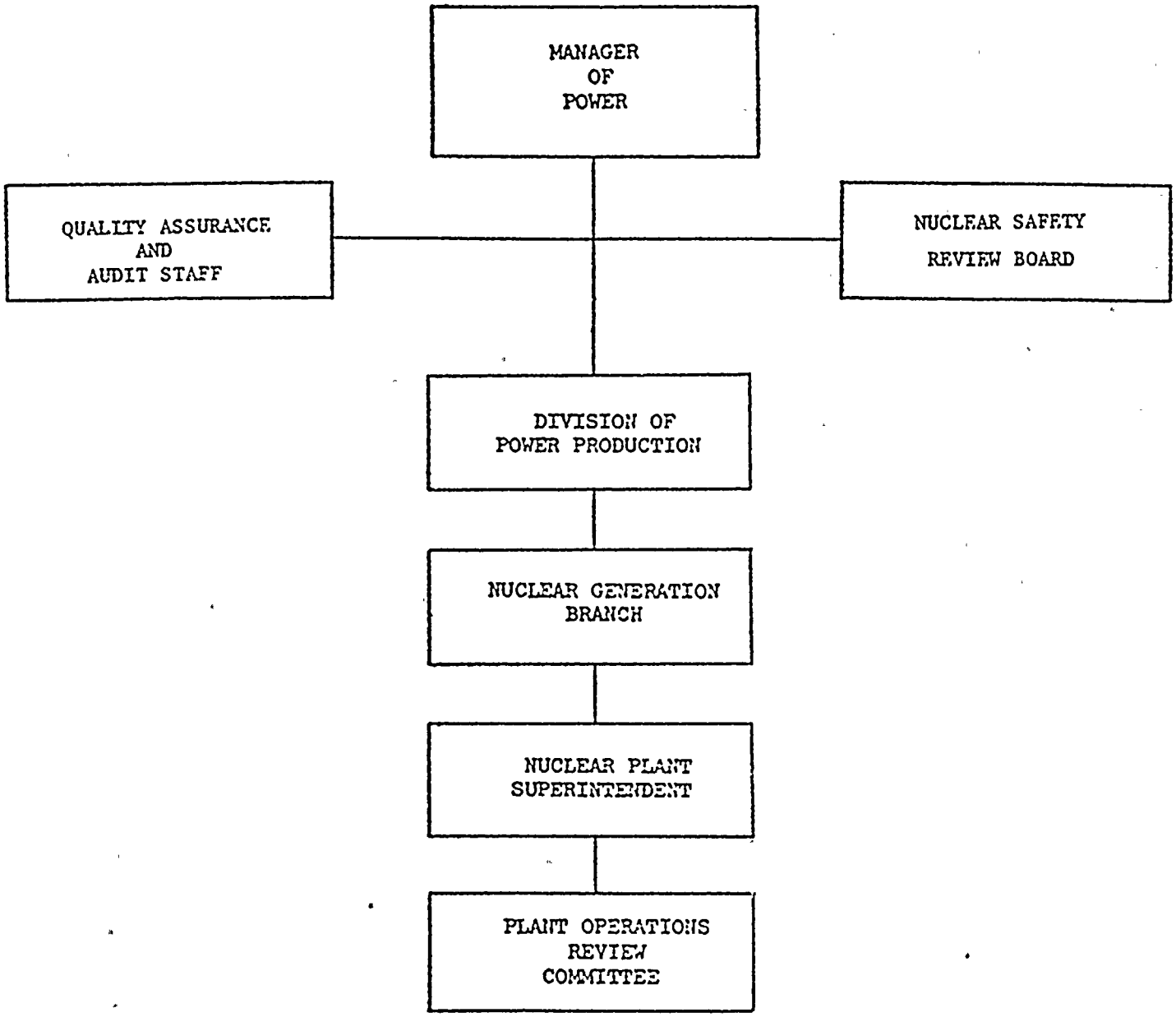
TVA Office of Power Organization for Operation of Nuclear Plants

FIGURE 6.1-1



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

FUNCTIONAL ORGANIZATION
FIGURE 6.1-2



BROWNS FERRY NUCLEAR PLANT
FINAL SAFETY ANALYSIS REPORT

REVIEW AND AUDIT
FUNCTION

FIGURE 6.2-1

IN-PLANT FIRE PROGRAM ORGANIZATION
BROWNS FERRY NUCLEAR PLANT

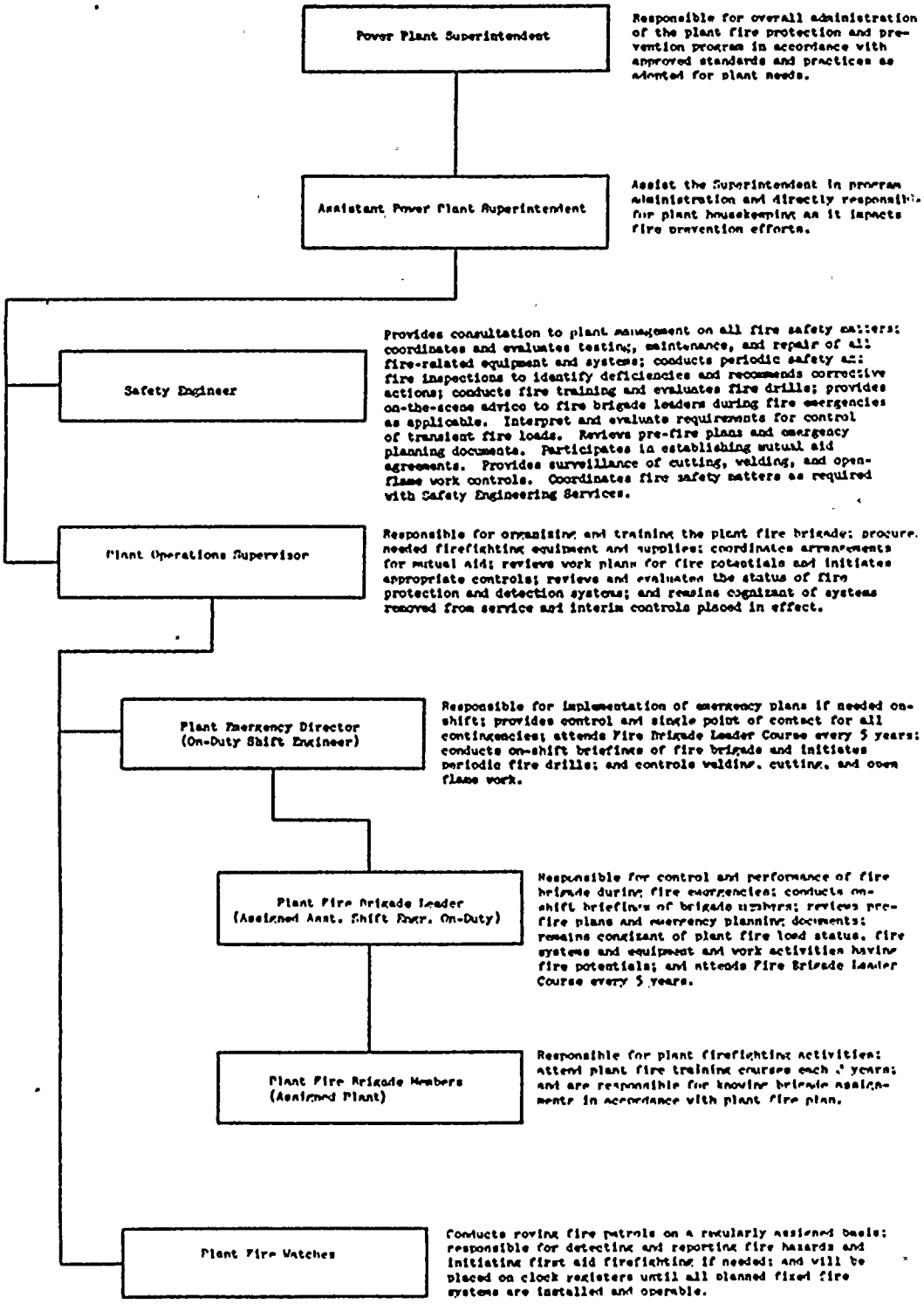


Figure 6.3-1

APPENDIX B

TO

FACILITY OPERATING LICENSE DPR -33

FOR BROWNS FERRY NUCLEAR PLANT UNIT 1

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-259

ENVIRONMENTAL TECHNICAL SPECIFICATIONS

FOR

BROWNS FERRY NUCLEAR PLANT

TABLE OF CONTENTS

TABLE OF CONTENTS (cont.)

1.0 DEFINITIONS

The following terms are defined for uniform interpretation of these specifications.

Administrative Terminology

Environmental limiting condition for operation--any limiting condition for plant operation as stated in Section 2 of the Browns Ferry Nuclear Plant Environmental Technical Specifications.

Unusual event with the potential for a significant environmental impact--an event that results in noncompliance with an environmental technical specification, or an event that results in uncontrolled or unplanned releases of chemical, radioactive, thermal, or other discharges from the Browns Ferry Nuclear Plant in excess of applicable Federal, state, and local regulations.

Thermal Properties

Thermal limits--limits defined for temperatures, spatial changes in temperature, and temporal changes in temperature within Wheeler Reservoir that are attributable to thermal discharges from Browns Ferry Nuclear Plant.

Intake temperature--the average temperature at a given time within the intake system at a point beyond the intake pumps.

Discharge temperature--the average temperature at a given time in the cooling water return channel or at the condenser outlet butterfly valves.

Delta T (ΔT)--the difference in temperatures of the river at the control monitors attributable to thermal discharges from Browns Ferry Nuclear Plant.

Instrumentation Properties

Accuracy--a measure of the difference between the true and measured values of a given parameter, hence a measure of error.

Minimum detectable level--that level below which a specific detector, instrument, or analysis is unable to detect the presence of a given constituent.

Sensitivity--the minimum change in the variable detected by a given sensor.

2.0 LIMITING CONDITIONS FOR OPERATION

2.1 THERMAL DISCHARGE LIMITS

Objective

The purpose of this specification is to limit the thermal stress on aquatic life in Wheeler Reservoir by operating Browns Ferry Nuclear Plant so as to meet the applicable water quality temperature standards of the State of Alabama.

Specification

The plant-induced reservoir water temperature at the 5-foot depth at the downstream control point shall not exceed the water temperature measured at the 5-foot depth of the upstream control monitor by more than the applicable maximum temperature rise (currently 5°F) nor shall the reservoir water temperature measured at the 5-foot depth at the downstream control point exceed the applicable maximum water temperature (currently 90°F †)due to the discharge of the condenser cooling water. If this limiting condition is exceeded, the plant operator shall initiate control measures. The control measures shall be (1) to reduce the waste heat discharged to the reservoir and/or (2) to request modifications in the releases from TVA's Guntersville and/or Wheeler Dams to increase the streamflow by the Browns Ferry plant.

TVA shall immediately advise the Commission if more stringent limitations (which would then govern) are imposed by EPA or the State.

Monitoring Requirement

The water temperature data collected by the thermal monitoring network is telemetered to the Browns Ferry meteorological station. The meteorological station will receive the data and automatically record the readings every 60 minutes. All temperature data are recorded on paper tape and maintained for record keeping purposes. The 5-foot depth temperature data which are used to prevent exceeding the limiting condition will be transmitted to the control room and will be visually displayed for monitoring purposes. The accuracy of the system and the sensitivity of the thermistor sensors are designed to be ±0.3°F and 0.01°F, respectively.

Three thermal monitors spaced across the reservoir in the vicinity of river mile 292.5 shall serve as the downstream control. Two monitors located above the plant, one located at about river mile 297.6, and a second located in this vicinity will provide the upstream water temperature data. The system is designed so that the downstream control monitors serve as backup for one another and similarly for the two upstream monitors. The locations of existing temperature monitors are displayed in Figure 2.1-1.

In the event the system described is out of service, an alternate method will be employed three times a day (once each shift) to measure the river temperature at the 5-foot depth in the vicinity of the upstream and downstream control monitors and thus determine the temperature rise and the maximum river water temperature below the plant. When such a method would result in an imminent and substantial endangerment to the safety of personnel, this paragraph shall not apply.

2.1 Continued

Bases

TVA, as a Federal agency, is required by Section 313 of the Federal Water Pollution Control Act Amendments of 1972 (P.L. 92-500) and by Executive Order 11507, "Prevention, Control and Abatement of Air and Water Pollution at Federal Facilities," to meet applicable Federal, state, and local water quality standards. On July 17, 1972, the State of Alabama adopted and on September 19, 1972, the Environmental Protection Agency approved thermal criteria for surface waters in the State of Alabama. The current applicable thermal standards are to limit the maximum temperature rise above natural temperature before the addition of artificial heat to 5°F and the maximum water temperature to 86°F. In the application of this temperature criteria the temperature shall be measured, in the case of Wheeler Reservoir, at a depth of 5 feet. The higher temperature limits during the special diffuser performance study during the summer of 1977 will be for brief periods and will not adversely affect the environment.

The Tennessee Valley Authority has taken action to comply with applicable thermal water quality standards of the State of Alabama in the operation of the 3-unit Browns Ferry facility by installing mechanical draft cooling towers. However, inadequate cooling tower performance has resulted in drastic curtailment of power generation during summer periods when peak load demands are critical on the TVA system to meet thermal standards.

The Browns Ferry Nuclear Plant Environmental Statement analyzed the environmental effects of operating the plant with a 10°F rise and 93°F maximum temperature limitation. This evaluation concluded that the 10°F and 93°F limitations would be adequate to protect aquatic life. Hydrologic studies recently conducted confirm that a 90°F limitation would not result in excessive temperature conditions in the cool water fisheries habitat downstream from the plant. An additional environmental assessment recently completed by TVA concludes that operation at or near the 90°F maximum temperature limitations will not result in adverse impacts on the biota of the reservoir.

TVA has requested from EPA and the State of Alabama that the maximum temperature limitation be increased to 90°F. The EPA stayed the 86°F maximum temperature requirements of the Browns Ferry NPDES permit in accordance with 40 CFR §125.35 and 40 CFR §125.36. EPA has requested while the stay is in effect that TVA comply with the 90°F maximum temperature limit. A letter confirming concurrence with EPA's position was received from the staff of Alabama Water Improvement Commission dated July 18, 1977.

All systems described for thermal discharge limits will be operational prior to any significant discharge of waste heat. The placement of the temperature monitoring instruments shall be such that compliance with water quality criteria will be demonstrated. The placement of the temperature sensors at the 5-foot depth in the waters of Wheeler Reservoir is in accordance with the requirements of the water quality criteria of the State of Alabama. The temperature data is converted to digital data at the station on the reservoir. The transmission, computer storage, and monitoring system is being used at other facilities and has performed accurately and reliably.

2.2 CHEMICAL

2.2.1 Makeup Water Treatment Plant Spent Demineralizer Regenerants

Objective

Treatment of makeup water treatment plant demineralizer waste (spent regenerant solutions) is provided to assure that the pH of the waste stream is within limits to protect the quality of the receiving stream and within applicable regulations.

Specification

The pH of the spent demineralizer regenerants shall be adjusted to within the range of 6.0 to 9.0 before release offsite.

Monitoring Requirement

The pH of spent demineralizer wastes shall be monitored in a waste collection sump or settling pond and shall be adjusted to within the range of 6.0 to 9.0 immediately before offsite release.

All measurements will be performed by plant personnel using standard instrumentation and operating instructions. Surveillance instructions and records will be kept on file at the plant.

Bases

Regeneration of makeup water treatment plant demineralizers requires the use of sulfuric acid and sodium hydroxide, which results in releases of SO_4^{--} and Na^+ and excess sulfuric acid and sodium hydroxide used in the regeneration cycle. Treatment of these wastes will consist of pumping the acid and caustic wastes into a settling pond to allow for dilution and neutralization. The wastes will be held in the pond as long as is practicable. Normally, natural losses such as evaporation will reduce the pond level. When offsite releases of waste water from a pond become mandatory, pH will be monitored and adjusted to within the range of 6.0 to 9.0.

Should circumstances force the direct offsite release of regenerative wastes from the makeup plant, the pH of the waste will be monitored, recorded and adjusted to within the range of 6.0 to 9.0 before discharging.

2.2 CHEMICAL (continued)

2.2.2 Chlorine

Objective

Control of the use of the chlorine as a biocide in the auxiliary raw cooling water system is exercised to assure that discharge to the receiving stream is below levels which could be harmful to aquatic biota.

Specification

A total chlorine residual of 0.05 mg/l shall not be exceeded at the discharge of the main condenser cooling water to the river due to chlorination of the auxiliary raw cooling water system. If a total chlorine residual of 0.05 mg/l is exceeded at the discharge of the main condenser cooling water to the river due to chlorination of the auxiliary raw cooling water system, the chlorine feed shall be immediately discontinued and not resumed until the feed rate has been reduced and the calibration of the feed equipment checked.

Monitoring Requirement

The residual chlorine in the auxiliary raw cooling water system shall be sampled weekly during periods when the raw cooling water systems are being chlorinated except as noted in Section 4.1.3. Concentration in the main condenser cooling water discharge will be computed using measured concentration and condenser cooling water and auxiliary raw cooling water flows.

As an alternate, the concentration in the condenser circulating water may be determined directly on a weekly basis, eliminating the need for raw cooling water sampling or condenser cooling water flow determination.

All analyses will be performed by plant personnel using standard analytical procedures for the determination of residual chlorine. The procedure used shall be one which has been approved by the Environmental Protection Agency for this purpose. Surveillance instructions and records will be kept on file in the plant.

Bases

Chlorine is to be used as a biocide for the control of Asiatic clams in the auxiliary raw cooling water system. It is expected that the use of chlorine for this purpose will be required only during the early and late stages of the spawning periods of Asiatic clams. The raw cooling water to be treated will be discharged to the main condenser cooling water system. Operating experience has shown that the reservoir water has a chlorine demand of about 0.5 mg/l. Due to the relative flow of the condenser cooling water and the auxiliary raw cooling water systems (approximately 20:1) and the chlorine demand of the diluted stream, it is expected that the chlorine residual will react sufficiently such that only chlorides will be discharged. The flow in the main condenser cooling water system will be determined from the design characteristics of the main condenser circulating water pumps operating during chlorination periods.

Page deleted

3.0 DESIGN FEATURES AND OPERATING PRACTICES

This section describes those design features and operating practices not covered in Section 2.0, "Limiting Conditions for Operation " and which, if changed, could result in significant effects on environmental impacts.

3.1 Chemical Usage

3.1.1 Oils and Hazardous Materials--Storage and Handling - Storage facilities for oils and hazardous materials will be protected by containment facilities to insure no releases to the aquatic environment. The plant areas where oils or other hazardous materials are routinely handled are equipped with separate drain systems and containment sumps.

The table below shows the materials stored, the quantities, and method of control.

Item	Storage	Total Storage Capacity	Control
Insulating Oil	2 tanks	74,000 gals.	Surrounded by 3" sand bed
Diesel Oil	2 tanks	142,000 gals.	Retention Basin (Sump)
Lubricating Oil	2 tanks	60,000 gals.	Retention Basin (Sump)
Sulfuric Acid	1 tank	3,400 gals.	Limestone Bed
Turbine Lube Oil	6 tanks	34,200 gals.	Sump Provided
Reactor Feed Pump Oil	9 tanks	9,000 gals.	Sump Provided
Sodium Hydroxide	1 tank	3,200 gals.	Sump Provided
Liquid Nitrogen	1 tank (insulated)		Isolated Storage
Askarel	All transformers		Sumps Provided
Chlorine	26 cylinders - 52,000 lbs.		Isolated Storage

3.1.2 Other Chemicals - Table 3.1.2-1 summarizes the uses of other chemicals used in plant processes, and the expected maximum quantity of chemical end products.

Table 3.1.2-2 shows the expected chemical concentrations of the effluent in the river after mixing.

3.2 Land Management

3.2.1 Power Plant Site - The site shall be appropriately landscaped as allowed by completion of construction. All areas which are either unpaved or not committed for specific purposes will be provided with appropriate vegetative cover.

3.2.2 Transmission Line Right-of-Way Maintenance

Objective

The sole purpose of this section is to provide reporting requirements (to USNRC) on herbicide usage, if any, for purposes of right-of-way maintenance regarding only those transmission lines under USNRC's jurisdiction for the Browns Ferry Nuclear Plant.

Specification

A statement as to whether or not herbicides have been used in maintaining rights of way for those transmission lines associated with the Browns Ferry Nuclear Plant shall be provided. If herbicides have been used, a description of the types, volumes, concentrations, manners and frequencies of application, and miles of right of way that have been treated shall be included.

Reporting Requirements

Information as specified above shall be provided in the annual environmental operating report.

Bases

Vegetation growth on a transmission line right of way must be controlled in such a manner that it will neither interfere with safe and reliable operation of the line nor impede restoration of service when outages occur. Vegetation growth is controlled by mechanical cutting and the limited use of herbicides. Selected chemicals approved by EPA for use as herbicides are assigned (by EPA) label instructions which provide guidance on and procedures for their use. A proposed program for chemical treatment of TVA transmission line right-of-way maintenance is submitted each year to the Federal Working Group on Pest Management for their review.

3.3 Onsite Meteorological Monitoring

The onsite meteorological monitoring program measures and documents meteorological conditions at the site, specifically at heights above ground that allow reasonable estimates of atmospheric dispersion conditions for airborne plant effluents. The onsite program shall conform to the recommendations and intent of Regulatory Guide 1.23, Onsite Meteorological Programs (February 1972), and include instruments to sense wind speed and direction at 10m, 46m, and 91m; to allow calculation of vertical temperature gradient between 10m and 46m and between 10m and 91m; and to measure ambient temperature and dew point at 10m. The location of the meteorological tower is as specified in Section 2.3.7 of the Browns Ferry Nuclear Plant Final Safety Analysis Report (see Amendment 63). A quality assurance program shall be in effect for all meteorological measurements and observations.

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 30 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.

4.0 ENVIRONMENTAL SURVEILLANCE

The program elements described below are designed to detect and measure the impact of plant operation on the environment. If on the basis of this program it is established that no significant adverse environmental impact has resulted or is likely to result from operation of the Browns Ferry Nuclear Plant, elements of the environmental surveillance program may be modified or terminated, in accordance with Subsection 5.6.3(c).

4.1 Ecological Surveillance

4.1.1 Abiotic

(a) Water Quality Surveys

Objective

Water quality surveys are performed quarterly in Wheeler Reservoir. Baseline levels for water quality parameters in Wheeler Reservoir were established by previous sampling and will be compared to that data received once the plant is in operation. Significant variations in compared numbers will be utilized to define potential water quality problems and provide solutions to these problems.

Specification

Water quality data in Wheeler Reservoir are determined quarterly at the locations shown in Table 4.1-1. Parameters monitored include dissolved oxygen, temperature, biochemical oxygen demand (5 day, 20° C.), chemical oxygen demand, pH, alkalinity, specific conductance, sodium, sulphates, chlorides, nitrogens (NH_3, NO_2 + NO_3, and organic), and solids (dissolved, suspended, and total). All analyses will be performed using standard documented analytical procedures for water quality analysis. Details of the analytical procedures are on file in the office of the Water Quality and Ecology Branch, Chattanooga, Tennessee.

Reporting Requirement

Water quality data are stored on the STORET computerized data-handling system that is operated by the U.S. Environmental Protection Agency and are also kept on file in the Water Quality and Ecology Branch office. These data are used for identifying existing water quality conditions in the plant area. The results will be summarized in annual reports of the nonradiological environmental monitoring program.

Bases

The reservoir monitoring program will, at a minimum, evaluate the parameters directly associated with the "added" waste discharges originating from Browns Ferry. Maintenance of these parameters at or within the applicable standards will help to assure satisfactory water quality conditions within Wheeler Reservoir.

(b) Thermal Plume Mapping

Objective

Verify the accuracy of thermal plume models used in predicting environmental effects from the thermal releases from the Browns Ferry plant.

Specification

Water temperature will be monitored at numerous depths from the water surface to the reservoir bottom at various locations in Wheeler Reservoir. Data will be used to verify predicted thermal plume models.

4.1.2 Biotic

(a) Benthic Monitoring

Objective

The benthic monitoring program will compare preoperational data with that obtained after Browns Ferry Nuclear Plant begins operation to ascertain if changes have occurred. Benthic organisms generally spend their life cycle in a localized area. Thus, species abundance should provide the best indication of induced change.

Specification

The program consists of quarterly sampling at the sampling stations identified in Table 4.1-1. All benthic monitoring will be performed using standard accepted biological sampling and enumeration procedures for benthic fauna. These procedures are on file in the office of the Water Quality and Ecology Branch, Muscle Shoals, Alabama. Benthic organisms are sorted from the sediment by washing fine material through a sieve and separating from the larger sediment particles. The four principal benthic macroinvertebrates selected for study are burrowing mayflies (Hexagenia), aquatic worms (Oligochaeta), midges (Chironomidae), and Asiatic clams (Corbicula).

Reporting Requirement

The results will be summarized in annual reports of the nonradiological environmental monitoring program.

Bases

The four benthic macroinvertebrates selected for study represent the predominant benthic fauna in Wheeler Reservoir. Normally currents in a reservoir do not affect the location and movement of benthic populations. Thus, these organisms can be studied at a specific location over an extended period to determine significant population changes.

(b) Phytoplankton Monitoring

Objective

The objectives of phytoplankton monitoring are to assess population changes within the areas monitored and to provide a basis for determining the effect of plant-induced population changes.

Specification

Quarterly monitoring of phytoplankton will be conducted at the locations shown in Table 4.1-1. All phytoplankton monitoring will be performed using standard accepted procedures for phytoplankton sampling, enumeration, and biomass and productivity determinations. These procedures are on file in the office of the Water Quality and Ecology Branch, Muscle Shoals, Alabama.

Reporting Requirement

The results will be summarized in annual reports of the nonradiological environmental monitoring program.

Bases

Changes to populations of phytoplankters, either in numbers or species, may indicate effects on algal growth and photosynthesis from natural variability in water temperature, light intensity, and nutrient concentrations as well as from plant-induced changes Changes may occur that are not detectable because of the high variability associated with sampling on a quarterly frequency. Additionally, prolonged exposure to high temperatures during late summer or fall enhances the growth of blue-green algae. In algal communities exposed to these conditions, dominance usually shifts successively from diatoms to green algae and eventually to blue-green algae.

Enumeration and biomass estimates are used to assess the standing crop of phytoplankton. Productivity measurements are used to determine the vitality of phytoplankton cells. The procedure is based on the amount of carbon-14 assimilated by viable cells over a measured period of time in a water sample of known volume.

(c) Zooplankton Monitoring

Objective

The objective of the zooplankton monitoring is to assess population changes and movement within the areas monitored and provide a basis for determining the effect of the plant on the zooplankton population.

Specification

Quarterly zooplankton samples will be collected at the locations shown in Table 4.1-1. All zooplankton monitoring will be performed using standard accepted zooplankton sampling and enumeration procedures. These procedures are on file in the office of the Water Quality and Ecology Branch, Muscle Shoals, Alabama.

Reporting Requirement

The results will be summarized in annual reports of the nonradiological environmental monitoring program.

Bases

Because zooplankton are important links in the aquatic food chain, taxonomy and population changes will be important indices in evaluating the effects of plant operation on reservoir ecology. However, since zooplankters are capable of limited movement and do change their vertical distribution during the daily cycle, data derived from sampling specified depths at discreet times may not present a complete picture. Since a relatively high degree of variability due to sampling procedures is expected, these studies are limited to providing a historical record for use in assessing such factors as gross population changes, percentage changes in groups (Copepoda, Cladocera, Rotifera), and the deletion or addition of any species after Browns Ferry Nuclear Plant becomes operational.

(d) Fish Population and Distribution Studies

Objective

Studies are to assess plant impact on movement of fish, relative abundance, creel harvest, species composition, and growth of fish.

Specification

Net sampling will be conducted quarterly at four of the locations shown in Table 4.1-1. All fisheries monitoring will be conducted using standard

accepted sampling and evaluation procedures. These procedures are on file in the office of the Division of Forestry, Fisheries, and Wildlife Development, Norris, Tennessee.

To determine normal movement in the reservoir, selected species of fish collected by trap nets will be tagged. Gill net catches will also supplement information on species composition, relative abundance, distribution, and movement. Electrofishing will be used to supplement the tagging of species not obtained in sufficient numbers by trap netting. Trap nets also furnish fish for routine growth studies.

Rotenone sampling of selected areas will be conducted during late August and early September of each year to estimate standing stocks, species composition, and reproductive success.

Creel census studies are conducted each month to establish catch per hour and per trip, species and weights of fish taken, and hours fished per trip in each of six areas of the reservoir. Previously recorded data will be the basis for determining the location and magnitude of the sport fishery before operation of the Browns Ferry Nuclear Plant.

Larval fish are also being investigated. Information on species, numbers, and distribution of larval fishes present in four areas of the reservoir during the sampling period before operation begins will be compared with data collected after the plant becomes operational to assess effects of plant operation.

Reporting Requirement

The results will be summarized in annual reports of the nonradiological environmental monitoring program.

Bases

An important interaction of Browns Ferry Nuclear Plant with the environment will be the heat dissipated from the plant in Wheeler Reservoir. The effect of the added heat on fish resources is to be determined.

(e) Entrainment of Fish Eggs and Larvae

Objective

To quantify the entrainment of fish eggs and larvae in the cooling water system.

Specification

The entrainment of fish eggs and larvae in the cooling water system shall be monitored weekly during the major spawning period of March through July and an estimate made of the total number of fish eggs and larvae entrained.

Monitoring will be performed using standard accepted sampling procedures which are on file in the office of the Division of Forestry, Fisheries, and Wildlife Development, Norris, Tennessee.

Reporting Requirement

The results will be summarized annually in the annual reports of the nonradiological environmental monitoring program.

Bases

A significant proportion of the river flow will be routed through the plant for cooling purposes, and during periods when larval fish are abundant there is the potential for entrainment of large numbers of fishes.

The specified study will determine the numbers of fish eggs and larvae entrained in the cooling water system resulting from plant operation and identify the need for possible corrective action.

(f) Fish Impingement on Intake Screens

Objective

To detect and quantify fish impingement upon the intake screens.

Specification

Once each week, fish which have been impinged on operating intake screens over the preceding 24 hours shall be estimated. The impinged fish shall be collected during screen washing and classified as: 1) shad and herring, 2) catfish, 3) bass (largemouth, smallmouth, and spotted bass), 4) crappie, 5) sunfish, 6) drum, and 7) other species.

Reporting Requirements

Five copies of a quarterly report to be prepared by TVA's Division of Power Production in coordination with the Division of Power Resource Planning shall be submitted to the USNRC Director of Division of Operating Reactors within 30 days following the end of each calendar quarter. The report shall inclu tabulated impingement data by screen and a summary of any specific studies or investigations which TVA is conducting to evaluate the significance of impingement losses or techniques for reducing these losses. A copy will be sent to TVA's Division of Forestry, Fisheries, and Wildlife Development for review and assessment. A summary of the impingement data (with the estimated total annual impingement per unit for each of the seven specified fish groups) shall be included in the annual nonradiological environmental operating report.

Bases

Quantification of impinged fish upon the intake screens will provide an assessment of fish losses from normal plant operation and identify the need for possible corrective action.

4.1.3 Special Studies

Objective

To demonstrate the adequacy of weekly sampling of chlorine residual during chlorination of the auxiliary raw cooling water systems by demonstrating that chlorine residual in auxiliary raw cooling water (RCW) systems remains relatively constant during chlorination.

Specification

TVA will perform special studies during the first two periods (including a spring and a fall period) of chlorination of the RCW systems after September 1975, which are of at least 3 weeks' duration. During the special studies period when the RCW systems are being chlorinated, samples will be taken daily from the RCW systems and analyzed for chlorine residual. Records of the daily sampling and analyses will be maintained and submitted to the NRC staff for their review following the end of the special study period. Chlorine feed rate and equivalent RCW concentration will be reported for the special studies period.

Sampling during the special study period will be considered to satisfy the monitoring requirements of Section 2.2.2 of the environmental technical specifications.

4.2 Radiological Environmental Monitoring Program

Objective

An environmental radiological monitoring program is conducted to verify projected or anticipated radioactivity concentrations and related public exposures.

Specification

An environmental monitoring program shall be conducted as described below at locations indicated in Figures 4.2-1, 4.2-2, and 4.2-3 and Tables 4.2-1, 4.2-2, 4.2-3, and 4.2-4, with sampling and analysis frequencies given in Table 4.2-1. Analytical techniques used shall be such that the detection capabilities in Table 4.2-5 are achieved.

1. Atmospheric Monitoring

   a. The atmospheric monitoring network is divided into three subgroups consisting of 11 monitoring stations. Five local monitors are located on or adjacent to the plant site, as shown in Figure 4.2-1. The four perimeter and two remote monitoring stations are shown on Figure 4.2-2. Atmospheric and terrestrial monitoring station locations for Browns Ferry Nuclear Plant are listed in Table 4.2-2.

      Each monitor shall be capable of continuously sampling air at regulated flow of approximately three cubic feet per minute through a particulate filter. In series with, but downstream of, the particulate filter is a charcoal filter used to collect iodine.

Each monitor has a collection apparatus to obtain rainwater on a continuous basis and a horizontal platform that is covered with gummed acetate to catch and hold heavy particulate fallout.

Each local monitor shall be equipped with a G-M tube located next to the particulate filter. The data from this detector are recorded on stripchart recorders located at the station and in the plant control room.

Thermoluminescent dosimeters shall be used to record gamma radiation levels at each remote and perimeter station (Figure 4.2-2) and at nine stations near the site boundary as shown in Figure 4.2-1. The TLD's shall be processed quarterly.

b. The particulate filters shall be removed weekly from each monitoring station and analyzed for gross beta activity. In addition, the filters for each station shall be composited monthly and quantitatively and qualitatively analyzed for at least 10 specific gamma-emitting radionuclides.*

The charcoal filters shall be removed weekly from each station and analyzed for ^{131}I.

Rainwater shall be collected monthly when available from each station and each sample is analyzed for at least 10 specific gamma-emitting radionuclides*, and tritium.

Gummed paper shall be changed monthly, ashed and the gross beta activity shall be determined.

2. <u>Reservoir Monitoring</u>

a. River water shall be sampled automatically from the locations shown in Table 4.2-3 and Figure 4.2-3.

b. Samples shall be collected automatically and analyzed monthly from three points on the Tennessee River. The samples shall be analyzed for at least 10 specific gamma-emitting radionuclides*, and shall be composited quarterly for tritium, ^{89}Sr and ^{90}Sr analyses.

Samples of sediment, clams, and a representative commercial and a representative game species of fish shall be collected at least semiannually from the locations noted in Table 4.2-3 and Figure 4.2-3. Plankton is collected in at least one of the two quarters of greatest plankton abundance during the year at the locations noted in Table 4.2-3 and Figure 4.2-3. Sediment, clam shells, fish, and when quantities are sufficient, plankton and clam flesh will be analyzed for at least 10 gamma-emitting radionuclides*. Strontium 89 and 90 content shall be determined in sediment and clam shells.

*The laboratory is presently gamma scanning a sample both quantitatively and qualitatively for the following radionuclides: ^{137}Cs, ^{134}Cs, $^{103,106}Ru$, $^{141,144}Ce$, ^{95}Zr, ^{95}Nb, ^{140}Ba-^{140}La, ^{131}I, ^{40}K, ^{60}Co, ^{58}Co, ^{54}Mn, ^{51}Cr, and ^{65}Zn.

3. Terrestrial Monitoring

a. Soil shall be collected at least once every three years from an area near the atmospheric monitors mentioned in paragraph 4.2.1.a, as indicated in Table 4.2-1 and Figures 4.2-1 and 4.2-2. Each sample shall be analyzed for at least 10 gamma-emitting radionuclides, ^{89}Sr and ^{90}Sr.

b. Milk shall be collected monthly when animals are off pasture, from at least four farms in the vicinity of the plant and analyzed as indicated in Table 4.2-1 and Figure 4.2-1.

During the seasons that animals producing milk for human consumption are on pasture, samples of fresh milk will be obtained* from these animals at representative locations that may be significantly affected by emissions from the Browns Ferry Nuclear Plant, and analyzed for their radioiodine content, calculated as iodine-131. Analysis will be carried out within eight days (one I-131 half life) of sampling. Suitable analytical procedures will be used to determine the radioiodine concentration to a sensitivity of 1.5 picocurie per liter of milk at the time of sampling. For activity levels at or above 1.5 picocurie per liter, overall error of the analysis will be within ±25%. Results will be reported as picocuries of I-131 per liter of milk at the time of sampling, in accordance with Reporting Requirements for Environmental Radiological Monitoring.

If the census of animals producing milk for human consumption indicates that an animal exists in an area where the calculated dose is $\geq$15 mrem/yr and the owner of the animal will not sell the milk to TVA for analysis, green leafy vegetables or other vegetation will be obtained from that location for analysis for I-131. The analysis and subsequent calculations will determine the dose to the individuals consuming the milk.

A census of animals producing milk for human consumption shall be conducted at the beginning and at the middle of the grazing season to determine their locations and number with respect to the site. The census shall be conducted under the following conditions:

1. Within a 1-mile radius from the plant site or within the 15 mrem/yr isodose line, whichever is larger, enumeration by a door-to-door or equivalent counting technique.

2. Within a 5-mile radius for cows and for goats, enumeration by using referenced information from county agricultural agents or other reliable sources.

*Milk samples will be collected and analyzed weekly in areas where the calculated dose to a child's thyroid exceeds 15 mrem/year. Sampling and analysis will be conducted semimonthly in areas where the dose is calculated to be $\leq$15 mrem/year. The calculational model as published in Regulatory Guide 1.109 and Regulatory Guide 1.111 shall be used.

If it is learned from this census that animals are present at a location which yields a calculated thyroid dose greater than from previously sampled animals, the new location shall be added to the surveillance program as soon as practicable if the farmer is willing to participate in the program. The sampling location having the lowest calculated dose may then be dropped from the surveillance program at the end of the grazing season during which the census was conducted. Also any location from which milk can no longer be obtained may be dropped from the surveillance program. The NRC shall be notified in writing that milk-producing animals are no longer present at that location. An additional milk sampling location will then be added to the program, with sampling frequency based on calculated dose.

c. Vegetation shall be collected at least quarterly from at least four of the farms mentioned in the preceding paragraph (see Figure 4.2-1). Each sample is analyzed for at least ten specific gamma-emitting radionuclides.

d. Food crops shall be collected annually within a 10-mile radius. Type and number of samples will vary according to availability (See Subsection 4.2.4).

e. Well water is collected automatically and analyzed monthly from the well most likely to be affected by the plant. (See Table 4.2-1 and Figure 4.2-1) A well remote from the plant is sampled monthly as a background. The samples shall be analyzed for at least ten gamma-emitting radionuclides.

f. Samples of potable surface water supplies shall be collected monthly from the locations in Table 4.2-4. The samples shall be analyzed for tritium, and at least ten specific gamma-emitting radionuclides.

4. Deviations are permitted from the required sampling schedule if specimens are unobtainable due to hazardous conditions, seasonal unavailability or to malfunction of automatic sampling equipment. If the latter, every effort shall be made to complete corrective action prior to the end of the next sampling period. All deviations from the sampling schedule shall be described in the annual report.

Bases

The operational environmental monitoring program is based upon a preoperational program which is described in Section 2.6 of the FSAR. Sample collection and analysis were initiated in April 1968, and will continue indefinitely.

Evaluations after plant startup will be made on the basis of baselines, considering geography and time of year where these factors are applicable, and by comparisons to control stations where the concentration of station effluents is expected to be negligible.

The reference samples provide a running background which will make it possible to distinguish significant radioactivity introduced into the environment by the operation of the station from that introduced by nuclear detonations and other sources.

In those cases where a statistically significant increase may be seen in a particular sampling vector but not in the control station, meteorology and/or specific radionuclide analysis will be used to identify the source of the increase.

The planned sampling frequencies and analysis sensitivities will assure that changes in the environmental radioactivity can be detected. The materials which first show changes in radioactivity are sampled most frequently. Those which are less affected by transient changes but show long term accumulations are sampled less frequently. However, the specific sampling dates are not crucial, and adverse weather conditions or equipment failure may on occasion prevent collection of specific samples.

A report shall be submitted to the USNRC at the end of each six months' period of operation specifying total quantities of radioactive material released to unrestricted areas in liquid and gaseous effluents during the previous six months and such other information on releases as may be required to estimate exposures to the public resulting from effluent releases. If quantities of radioactive material released during the reporting period are unusual for normal reactor operations, including expected operational occurrences, the report shall cover this specifically.

A concentration of I-131 in milk of 3.1 picocuries per liter will result in a dose to the thyroid of a 0 - 2-year-old child of 15 mrem/yr, based upon consumption of one liter per day for the year. To assure that no child will receive a dose of greater than 15 mrem/year/reactor to the thyroid, it is necessary to know the radioiodine concentration in the milk to the sensitivity of 1.5 pCi/liter.

5.0 ADMINISTRATIVE CONTROLS

Objective

This section describes the administrative and management controls established to provide continuing protection to the environment and to implement the environmental technical specifications. Measures to be specified in this section include the assignment of responsibilities, organizational structure, operating procedures, review and audit functions, and reporting requirements.

Specifications

5.1 Responsibility

5.1.1 The power plant superintendent has responsibility for operating the plant within the limiting conditions for operation (LCO).

5.1.2 The Director, Division of Environmental Planning, is responsible for the environmental monitoring program outside the plant.

5.2 Organization

5.2.1 The organization of TVA management which directly relates to operation of the plant is shown on Figure 5.2-1.

5.2.2 The principal divisions within TVA which are concerned with environmental matters related to nuclear power plant operation are the Division of Power Production (DPP), Division of Forestry, Fisheries, and Wildlife Development (FFWD), Division of Power Resource Planning (DPRP), and the Division of Environmental Planning (DEP). The DPP and DPRP are in the Office of Power. The Office of Power Quality Assurance and Audit Staff is a special staff within the Office of Power. The Office of Power, DEP, and FFWD report to the General Manager. This is depicted in Figure 5.2-2.

5.3 Review and Audit

5.3.1 The Director, DEP, is responsible for review of plant operation related to LCO to insure that plant operation is being conducted within the limits defined in Section 2 of this document.

5.3.2 The Office of Power Quality Assurance and Audit Staff shall conduct a periodic audit of the environmental monitoring program at intervals not to exceed one year.

5.3.3 The DPRP and/or DEP shall review and contribute to the following items:

a. Preparation of the proposed environmental technical specifications.

b. Coordination of environmental technical specification development with the safety technical specifications to avoid conflicts and maintain consistency.

c. Proposed changes to the environmental technical specifications and the evaluated impact of the change.

d. Proposed written procedures, as described in Section 5.5 and proposed changes thereto which could significantly affect the plant's environmental impact.

e. Proposed changes or modifications to plant systems or equipment which could significantly affect the plant's environmental impact and the evaluated impact of the changes.

f. Results of the environmental monitoring programs prior to their submittal in each Annual Operating Report. See Sections 5.6.1 and 5.6.2.

g. Reported instances of violations of environmental technical specifications. Where investigation indicates, evaluation and formulation of recommendations to prevent recurrence.

5.4 Action to be Taken if an Environmental LCO is Exceeded

5.4.1 Follow any remedial action permitted by the technical specifications until the condition can be met.

5.4.2 The DPP shall promptly report the violation to the Manager of Power and the Director, DEP.

5.4.3 DEP will then conduct an independent investigation of the incident. DEP will then report the results of its investigation to the Manager of Power, the Office of Power Quality Assurance Manager, the Director, DPP, and the Director, DPRP.

5.4.4 An investigation of reported or suspected incidents involving violation shall be initiated. This investigation shall consist of the circumstances leading to and resulting from the situation together with recommendations to prevent a recurrence. The results shall be submitted to the Manager of Power, the Office of Power Quality Assurance Manager, the Director, DPP, the Director, DPRP, and the Director, DEP.

5.4.5 Notification of the Director of the Regional Regulatory Operations Office, Region II of NRC within 24 hours shall be made as specified in Section 5.6.3. Reporting requirements for this paragraph are described in Section 5.6.3.

5.5 Procedures

5.5.1 Detailed written procedures for the in-plant nonradiological monitoring program, including check-off lists, where applicable, shall be prepared by DPP and approved by the plant superintendent and adhered to.

A quality control program has been established with the Alabama Department of Public Health Environmental Health Administration Laboratory and the Environmental Protection Agency, Montgomery, Alabama. Samples of air, water, milk, and vegetation collected around the BFNP are forwarded to these laboratories for analysis; and results are exchanged for comparison.

An internal quality control program is being conducted whereby roughly one tenth of all samples are analyzed in duplicate. A quality control program is conducted with the Environmental Protection Agency in Las Vegas in which spiked samples are analyzed and the results compared.

5.5.2 Detailed written procedures for the environmental monitoring program outside the plant, including check-off lists, where applicable, shall be prepared, approved by the Director, DEP, and adhered to.

5.5.3 All procedures described in Section 5.5.1 and all changes thereto shall be reviewed and approved prior to implementation and on an annual basis thereafter by the plant management. Temporary changes to procedures which do not change the intent of the original procedure may be made, provided such changes are documented and are approved by two of the following plant personnel:

Superintendent
Assistant Superintendent
Operations Supervisor
Assistant Operations Supervisor
Shift Engineer

5.6 Reporting Requirements

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

5.6.2 Routine Reporting

a. A summary report shall be prepared by the DPP for both the inplant monitoring and the nonradiological environmental monitoring programs and submitted by the Manager of Power, TVA, to the Director of Division of Operating Reactors, NRC, as part of the Annual Operating Report within 90 days of December 31.

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 environment. 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.

2. Results of all radiological environmental samples taken shall be summarized and tabulated on an annual basis. In the event that some results are not available within the 120-day period, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted as soon as possible in a supplementary report.

5.6.3 Non-Routine Reports

a. Radiological

Anomalous Measurements

1. If, during any 12-month report period, a measured level of radioactivity in any environmental medium other than those associated with gaseous radioiodine releases exceeds ten times the control station value, a written notification will be submitted within one week advising the NRC of this condition.* This notification should include an evaluation of any release conditions, environmental factors, or other aspects necessary to explain the anomalous result.

2. If, during any 12-month report period, a measured level of radioactivity in any environmental medium other than those associated with gaseous radioiodine releases exceeds four times the control station value, a written notification will be submitted within 30 days advising the NRC of this condition. This notification should include an evaluation of any release conditions, environmental factors, or other aspects necessary to explain the anomalous result.

3. If individual milk samples show I-131 concentrations of 10 picocuries per liter or greater, a plan shall be submitted within 10 days advising the NRC of the proposed action to ensure the plant related annual doses will be within the design objective of 15 mrem/yr/reactor to the thyroid of any individual.

4. If milk samples collected over a calendar quarter show average concentrations of 6.0 picocuries per liter or greater, a plan shall be submitted within 30 days advising the NRC of the proposed action to ensure the plant-related annual doses will be within the design objective of 15 mrem/yr/reactor to the thyroid of any individual.

*In the case of a tentatively anomalous value for radiostrontium, a confirmatory reanalysis of the original, a duplicate or a new sample may be desirable. In this instance the results of the confirmatory analysis shall be completed at the earliest time consistent with the analysis, and if the high value is real, the report to the NRC shall be submitted within one week following this analysis.

5. If such levels as discussed in 5.6.3(a)3 and 5.6.3(a)4 can be definitely shown to result from sources other than the Browns Ferry Nuclear Plant, the reporting action called for in 5.6.3(a)3 and 5.6.3(a)4 need not be taken. Justification for assigning high levels of radioactivity to sources other than the Browns Ferry Nuclear Plant must be provided in the annual report.

b. Nonradiological

In the event a limiting condition for operation is exceeded or an unusual event with a potential for a significant environmental impact occurs, a report shall be made within 24 hours by telephone or telegraph to the Director of the Regional Office of Inspection and Enforcement, Region II, followed by a written report summarizing the results of investigations by DEP and DPP within 10 days from the Office of Power to the Director of the Regional Office of Inspection and Enforcement, Region II (copy to the Director of Division of Operating Reactors).

c. Changes

1. Where a change to the plant design, the plant operation, or to procedures is planned which could have a significant adverse effect on the environment or which involves an environmental matter or question not previously reviewed and evaluated by the NRC, a request for the change shall be made to the NRC before implementation.

2. Changes or additions to permits and certificates required for the protection of the environment shall be reported. When the required changes are submitted to the concerned agency for approval, they shall also be submitted to the Director, Division of Operating Reactors, USNRC, for information.

3. Requests for changes in environmental technical specifications shall be submitted to the Director, Division of Operating Reactors, USNRC, for prior review and authorization.

5.7 Environmental Records

5.7.1 Operational information concerning the inplant portion of the environmental technical specifications shall be kept by DPP in a manner convenient for review. This includes plant records and/or logs as indicated below:

a. Related plant operations

b. Related maintenance activities

c. LCO violation

d. Updated, corrected, and as-built drawings of the plant

Item (a) through (c) above shall be retained for a period of at least six years and item (d) shall be retained for the life of the plant.

5.7.2 Records and/or logs shall be maintained by DEP and/or DWM in a manner convenient for review. This information concerning the environmental monitoring program is indicated below:

a. Checks, inspections, tests, and calibration of components and systems.

b. Principal maintenance activities associated with environmental monitoring equipment and systems.

c. Results of environmental monitoring surveys related to BFNP.

Items (a) and (b) shall be retained for a period of at least six years and item (c) shall be retained for the life of the plant.

Table 3.1.2-1

Sources of Added Chemicals and Resulting End Product Chemicals

System	Chemical Added Source Chemical	Maximum[a] Annual Use lbs	Waste End Product Chemical	Maximum Resulting[a] End Product Annual lbs	Maximum Resulting[a] End Product Mean Daily lbs
Makeup Water Treatment Plant	Alum $Al_2(SO_4)_3 \cdot 18\ H_2O$	15,800	$Al(OH)_3$[b]	3,700	~10
			SO_4^{--}	6,800	~21
			Suspended solids[b,c]	13,500	~37
	Soda Ash $Na_2\ CO_3$ (100%)	7,900	Na^+	3,400	~10
	Sodium Hypochlorite NaOCl (21% Solution)	3,950	Na^+	260	~ 1
			OCl^-	570	~ 2
	Coagulation Aid	590	Coag. Aid[b]	590	~ 2
Makeup water Treatment Plant Demineralizer Regeneration	Sulfuric Acid 98%	270,000	SO_4^{--}	259,000	~710
	Sodium Hydroxide (50%)	205,000	Na^+	59,000	~160
Auxiliary Steam Generator Blowdown	Ammonia	Variable[d]	NH_3	6	~0.02
	Hydrazine	Variable[e]	NH_3	0.4	~0.001
Raw cooling water System	Chlorine	Variable	OCl^- and Cl^-	Variable	1,620

a. Based on 24-hour operation 365 days/year at demonstrated maximum capacity of equipment.
b. Suspended materials that will make up the water treatment plant sludge, on a dry weight basis.
c. Estimates from suspended solids data observed at TRM 300.3.
d. Ammonia will be added as needed to keep pH of system at 9.0.
e. Hydrazine will be added as needed as a DO scavenger.

Table 3.1.2-2

SUMMARY OF CHEMICAL DISCHARGES

Waste Product Chemical	Maximum[a] Annual Discharge of Product Chemical lbs	Waste[b] Product Chemical Contribution to Discharge Concentrations mg/l	Observed Concentrations in Reservoir Water at TRM 300.3 mg/l		Total Concentrations[c] in River After Mixing mg/l		Maximum[g] Allowable Concentrations in River mg/l
			Average	Maximum	Average	Maximum	
Sulfates (SO_4^{--})	265,800	0.031	15.0	23.0	15.027	23.027	250
Sodium (Na^+)	62,700	0.007	5.92	9.18	5.9263	9.1863	d
Chlorides[e]	34,600	0.068	14.0	21.0	14.060	21.060	250
Ammonia[f] NH_3	6.4	nil	0.02	0.07	0.02	0.07	d
Total Dissolved Solids	363,106	0.106	104.0	129.0	104.093	129.093	500

a. Based on 24-hour operation 365 days per year at demonstrated maximum capacity of equipment and chemical requirements.
b. Discharge flows based on 3-unit operation.
c. Concentrations based on downstream riverflow of 5,000 ft^3/s. However, heat dissipation considerations will require minimum of 23,000 ft^3/s for open mode.

d. No specific standard has been identified but contribution to dissolved solids has been included.
e. Computation is for chlorides since the chlorine demand of the cooling water is such that no residual chlorine will be discharged. Chlorides and total dissolved solids reflect maximum daily use of chlorine in raw cooling water.
f. Ammonia and hydrazine added to auxiliary steam generator for pH and dissolved oxygen control. Hydrazine conservatively assumed to decompose to ammonia.
g. Alabama Water Improvement Commission Stream Standards.

Table 4.1-1

SUMMARY OF NONRADIOLOGICAL MONITORING PROGRAM

BROWNS FERRY NUCLEAR PLANT

Station TRM	Water Samples	Zooplankton, Chlorophyll and Phytoplankton Sampling	Productivity Measurements	Benthic Fauna	Sediment	Fish[a]
Second Creek Embayment Station						X
277.98	X[b]	X	X	X	X	
283.94	X[c]	X	X	X		X
Elk River Embayment Station						X
288.78	X[b]	X	X	X	X	
291.76	X[c]	X	X	X		X
293.70	X[b]	X	X	X	X	X
295.87	X[c]	X	X	X		
299.00						X
301.06		X	X	X		
307.52	X[b]	X	X	X	X	X

X - Indicates at least one quarterly sample collected at the specified station.

a. Fish sampling at a specific station will be by either gill net, trap net, rotenone, or electrofishing. However, depending upon the sampling method the frequency of sampling at each location may be less than quarterly.

b. Analysis - Dissolved oxygen and temperature.

c. Analysis - Dissolved oxygen, temperature BOD_5, COD, pH, alkalinity, specific conductance, Na, SO_4, chlorides, nitrogens (NH_3, NO_2+NO_3, and organic) and solids (dissolved, suspended, and total).

Table 4.2-1

Environmental Radiological Monitoring

Exposure Pathway and/or Sample	Number of Samples and Locations	Sampling and Collection Frequency	Type of Frequency of Analysis
AIRBORNE			
Particulates	4 samples from locations (in different sectors) at or near the site boundary 1 sample from the residence having the highest χ/Q 4 samples from communities approximately 10 miles distant from the plant 2 samples from control locations greater than 10 miles from the plant	Continuous sampler operation with sample collection weekly	Gross beta following filter change Composite (by location) monthly for gamma scan. Composite quarterly for ^{89}Sr, ^{90}Sr. If any filter indicates a gross beta concentration 1.0 pCi/m^3 greater than the average of the control stations, a gamma scan will be performed on the filter
Radioiodine	Samples from same locations as air particulates	Continuous sampler operation with filter collection weekly	^{131}I weekly
Fallout	Samples from same locations as air particulates	Heavy particle fallout collected continuously on gummed acetate paper with paper collection monthly	Gross beta monthly
Rainwater	Samples from same locations as air particulates	Rainwater collected continuously with composite sample analyzed monthly	Gamma scan, monthly
Soil	Samples from same locations as air particulates	Once per 3 years	Gamma scan, ^{89}Sr, ^{90}Sr once each 3 years

Table 4.2-1 (Continued)

Exposure Pathway and/or Sample	Number of Samples and Locations	Sampling and Collection Frequency	Type and Frequency of Analysis
DIRECT	2 or more dosimeters placed at the air particulate sampling stations located greater than 5 miles from the plant	Quarterly	Gamma dose quarterly
	2 or more dosimeters placed at 8 locations (in different secotrs) at or near the site boundary		
WATERBORNE			
Surface	1 sample upstream 1 sample immediately downstream of discharge 1 sample downstream, after dilution	Collected by automatic sequential-type sampler with composite sample taken monthly	Gamma scan monthly Composite for tritium, ^{89}Sr and ^{90}Sr quarterly
Ground	1 sample adjacent to plant	Collected by automatic sequential-type sampler with composite sample taken monthly	Gamma scan monthly ^{3}H quarterly on monthly composite
	1 sample from ground water source upgradient	Monthly	Gamma scan monthly ^{3}H quarterly on monthly composite
Drinking	1 sample at the first potable surface water supply downstream from the plant	Collected by automatic sequential-type sampler with composite sample taken monthly	

Table 4.2-1 (Continued)

Exposure Pathway and/or Sample	Number of Samples and Locations	Sampling and Collection Frequency	Type and Frequency of Analysis
	1 sample at the second downstream potable surface water supply (19.1 miles downstream)	Monthly	Gross beta and gamma scan monthly. Composite for tritium, ^{89}Sr, and ^{90}Sr quarterly
	2 samples at control locations	Monthly	
AQUATIC			
Sediment and Asiatic Clams	1 sample upstream from discharge point		
	1 sample in immediate downstream area of discharge point	Semiannually	Gamma scan, ^{89}Sr, and ^{90}Sr analyses semiannually (^{89}Sr, and ^{90}Sr on sediment and clam shells only)
	2 samples downstream (4.9 and 15.7 miles)		
Plankton	1 sample upstream from discharge point		
	1 sample in immediate downstream area of discharge point	Semiannually	
	1 sample downstream (15.7 miles)		Gross beta semiannually. Gamma scan, ^{89}Sr, ^{90}Sr, when sufficient quantities are available
INGESTION			

Table 4.2-1 (Continued)

Exposure Pathway and/or Sample	Number of Samples and Locations	Sampling and Collection Frequency	Type and Frequency of Analysis
Milk	4 samples from dairy farms in the immediate vicinity of the plant	Weekly or semimonthly (when animals are on pasture) depending on calculated doses.* Monthly when animals are off pasture.	^{131}I analysis weekly or semimonthly when cattle are on pasture
	1 sample from control location		Gamma scan, ^{89}Sr, and ^{90}Sr monthly
Fish	1 sample each of a commercial and a game species in Guntersville Reservoir above the plant		
	1 sample each of a commercial and a game species in Wheeler Reservoir near the plant	Semiannually	Gamma scan semiannually.
	1 sample each of a commercial and a game species in Wilson Reservoir below the plant		
Vegetation (Pasturage and Grass)	4 samples from the dairy farms from which milk is obtained	Quarterly	Gamma scan,

*Milk samples will be collected and analyzed weekly in areas where the calculated dose toa child's thyroid exceeds 15 mrem/year. Sampling and analysis will be conducted semimonthly in areas where the dose is calculated to be $\leq$15 mrem/year.

Table 4.2-1 (Continued)

Exposure Pathway and/or Sample	Number of Samples and Locations	Sampling and Collection Frequency	Type and Frequency of Analysis
Fruits and Vegetables	Samples of corn, green beans, tomatoes, and potatoes grown at private gardens and/or farms in the immediate vicinity of the plant location determined by census. 1 sample of each of the same foods grown at greater than 10 miles distance from the plant.	Annually, at time of harvest	Gamma scan on edible portion

Table 4.2-2

Atmospheric and Terrestrial Monitoring Station Locations

Browns Ferry Nuclear Plant

Sample Station	Location Distance and direction from plant
LM-1 BF	1.0 mile N
LM-2 BF	0.9 miles NNE
LM-3 BF	1.0 miles NE
LM-4 BF	1.7 miles NNW
LM-5 BF	2.5 miles WSW
PM-1 BF (Rogersville, AL)	13.8 miles NW
PM-2 BF (Athens, AL)	10.9 miles NE
PM-3 BF (Decatur/Trinity, AL)	8.2 miles SSE
PM-4 BF (Courtland, AL)	10.5 miles WSW
RM-1 BF (Muscle Shoals, AL)	32.0 miles W
RM-2 BF (Lawrenceburg, TN)	40.5 miles NNW

Table 4.2-3

TYPES AND LOCATIONS OF SAMPLES COLLECTED FOR OPERATIONAL RAD ANALYSIS IN WHEELER RESERVOIR IN RELATION TO THE BROWNS FERRY NUCLEAR PLANT

TRM Station	Water[a]	Plankton[b]	Asiatic Clams	Sediment	Fish[c]
307.52		X	X	X	
305.0	X				
293.70			X	X	
293.5	X				
291.76		X			
288.78			X	X	
285.2	X				
277.98		X	X	X	

a. Collected automatically
b. Vertical tows
c. G/E - Gill net and/or electroshocker will be used for collection. Samples of fish will be collected from Guntersville, Wheeler, and Wilson Reservoirs.

Table 4.2-4

LISTING OF TENNESSEE RIVER SURFACE WATER SUPPLIES TO BE SAMPLED IN ENVIRONMENTAL MONITORING PROGRAM

Supply	Distance from Plant (miles)
Courtland (Champion Paper Co.)[a]	11.6
Decatur[b]	12.0
Wheeler Hydro Plant	19.1
Sheffield	39.7

a. First potable water supply downstream of the plant. Sample collected automatically and analyzed monthly.
b. Decatur is upstream of the Browns Ferry Nuclear Plant.

TABLE 4.2-5

Detection Capabilities for Environmental Sample Analysis

	Nominal Lower Limit of Detection (LLD)					
Analysis	Water (pCi/l)	Airborne Particulate or Gas (pCi/m^3)	Fish, Meat, or Poultry (pCi/kg, wet)	Milk (pCi/l)	Vegetation (pCi/kg, wet)	Soil (pCi/kg, dry)
gross beta	2	.01				
^{3}H	330					
^{144}Ce*	30	.03	90		115	
^{51}Cr*	60	.07	200		240	
^{131}I	15*	.01*	50*	1.5	70*	
^{106}Ru*	30	.04	150		150	
^{134}Cs*	10	.01	40		50	
^{137}Cs*	10	.01	40	10	50	120
^{95}Zr-Nb*	10	.01	40		50	
^{58}Co*	15	.02	55		70	
^{54}Mn*	10	.02	40		50	
^{65}Zn*	15	.02	70		75	
^{60}Co*	10	.01	30		40	
^{40}K*	100	.10	400		500	
^{140}Ba-La*	15	.02	150	15	145	
^{89}Sr	2	.005	40	10		
^{90}Sr	2	.001	8	2		150

* These measurements are performed by gamma spectroscopy. The LLD values are calculated by the method of Pasternack and Harley as discussed in HASL-300. The original method was published in Nucl. Instr. Methods 91, 533-40 (1971). These LLD values are expected to vary depending the activities of components in the samples. These figures will be rarely, if ever, attainable. Water is counted in a 3.5 liter Marinelli beaker. Vegetation is counted in a 1-pint container as dry weight, then corrected to wet weight using an average moisture content of 80%. Average dry weight is 125 grams. Fish, meat, and poultry are counted in a 1-pint container as dry weight, then corrected to wet weight using an average moisture content of 70%. Average dry weight is 250 grams. Air Particulate Filters are counted in a well crystal. The counting system consists of a multichannel analyzer and either a 4" x 4" solid NaI crystal or a 4" x 5" NaI well crystal. The counting time is 4,000 seconds. All calculations are performed by the least-squares computer program ALPHA-M. The assumption is made that all samples are analyzed within one week of collection.

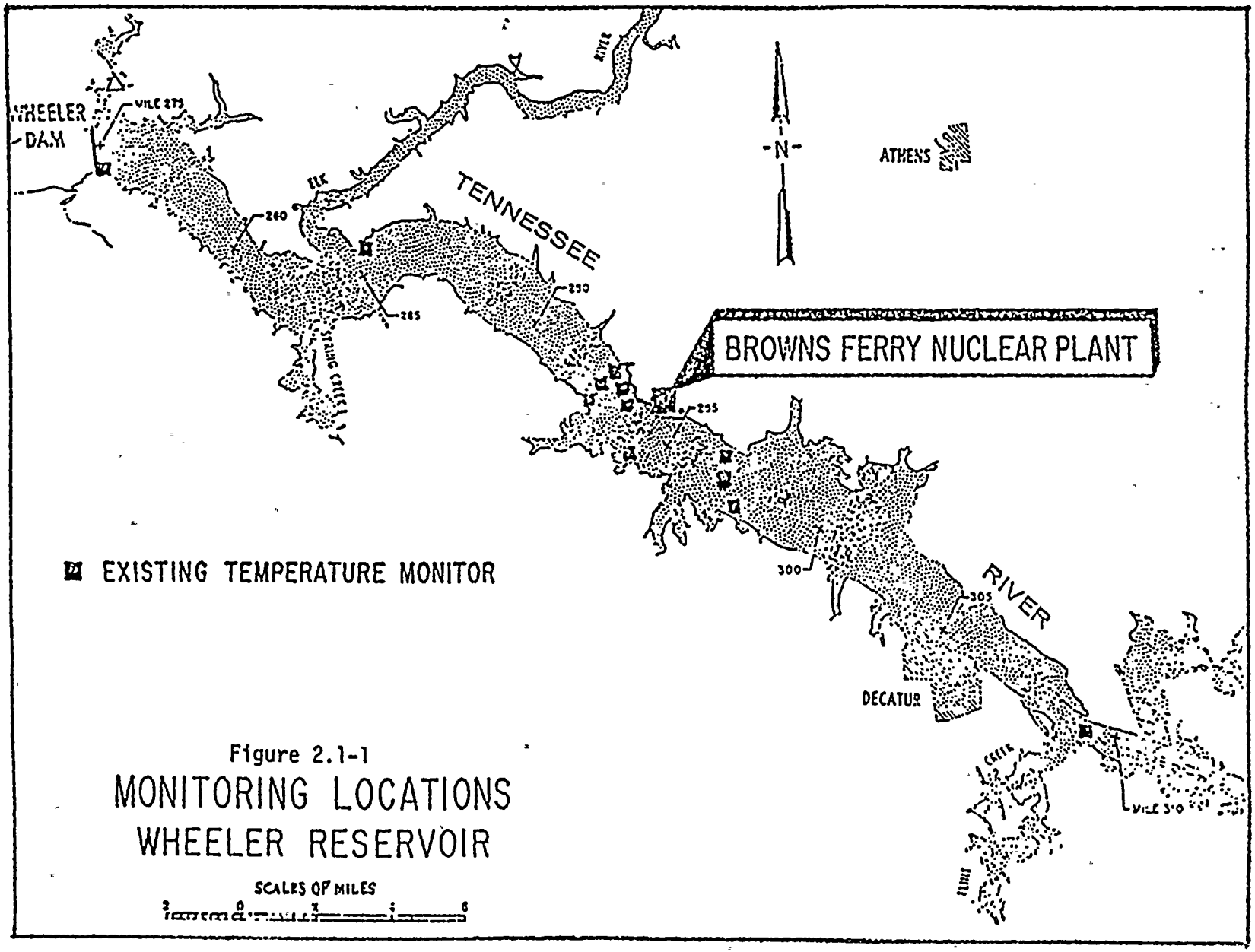


Figure 2.1-1
MONITORING LOCATIONS
WHEELER RESERVOIR

Figure 4.2-1

LOCAL MONITORING STATIONS

BROWNS FERRY NUCLEAR PLANT

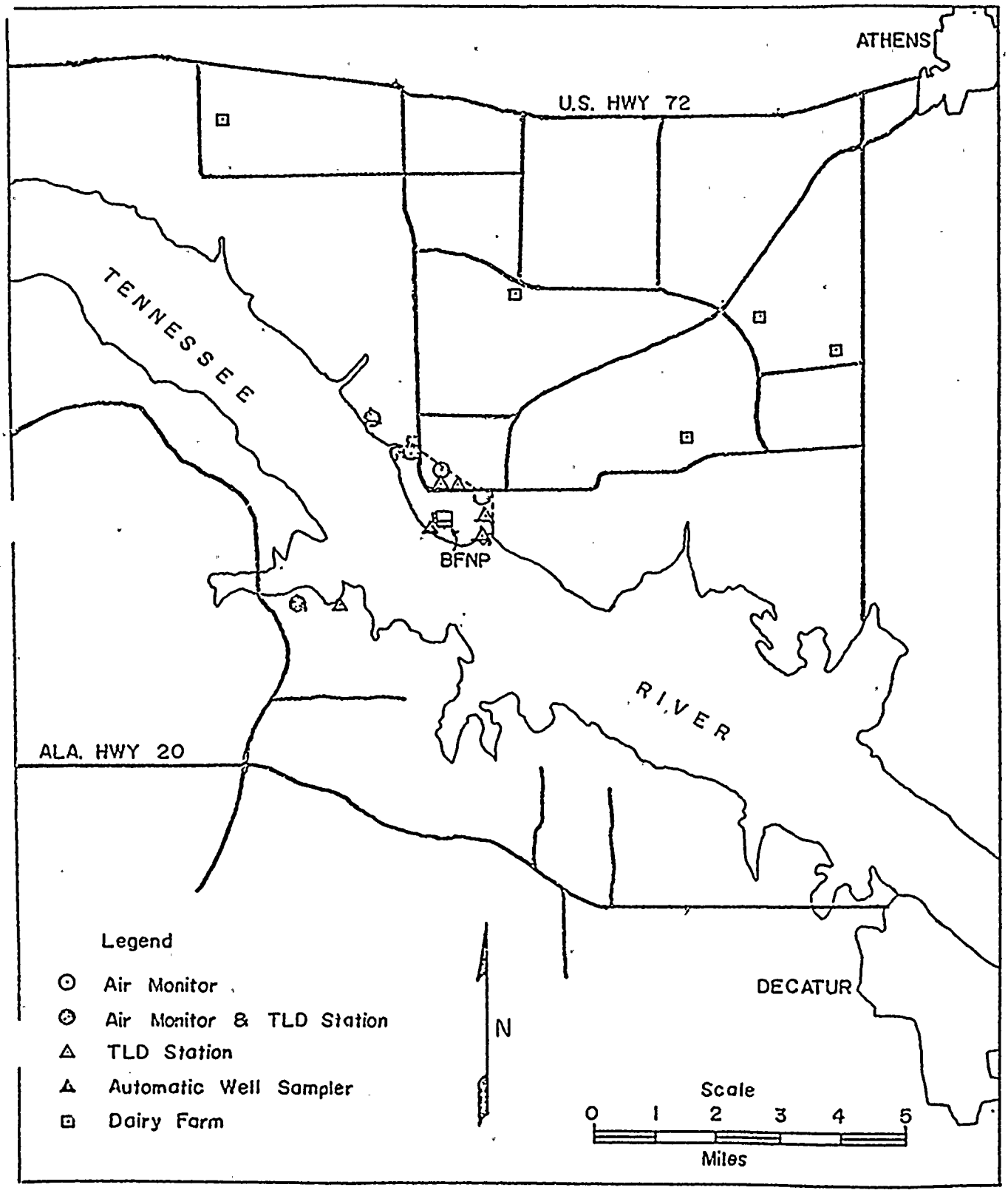
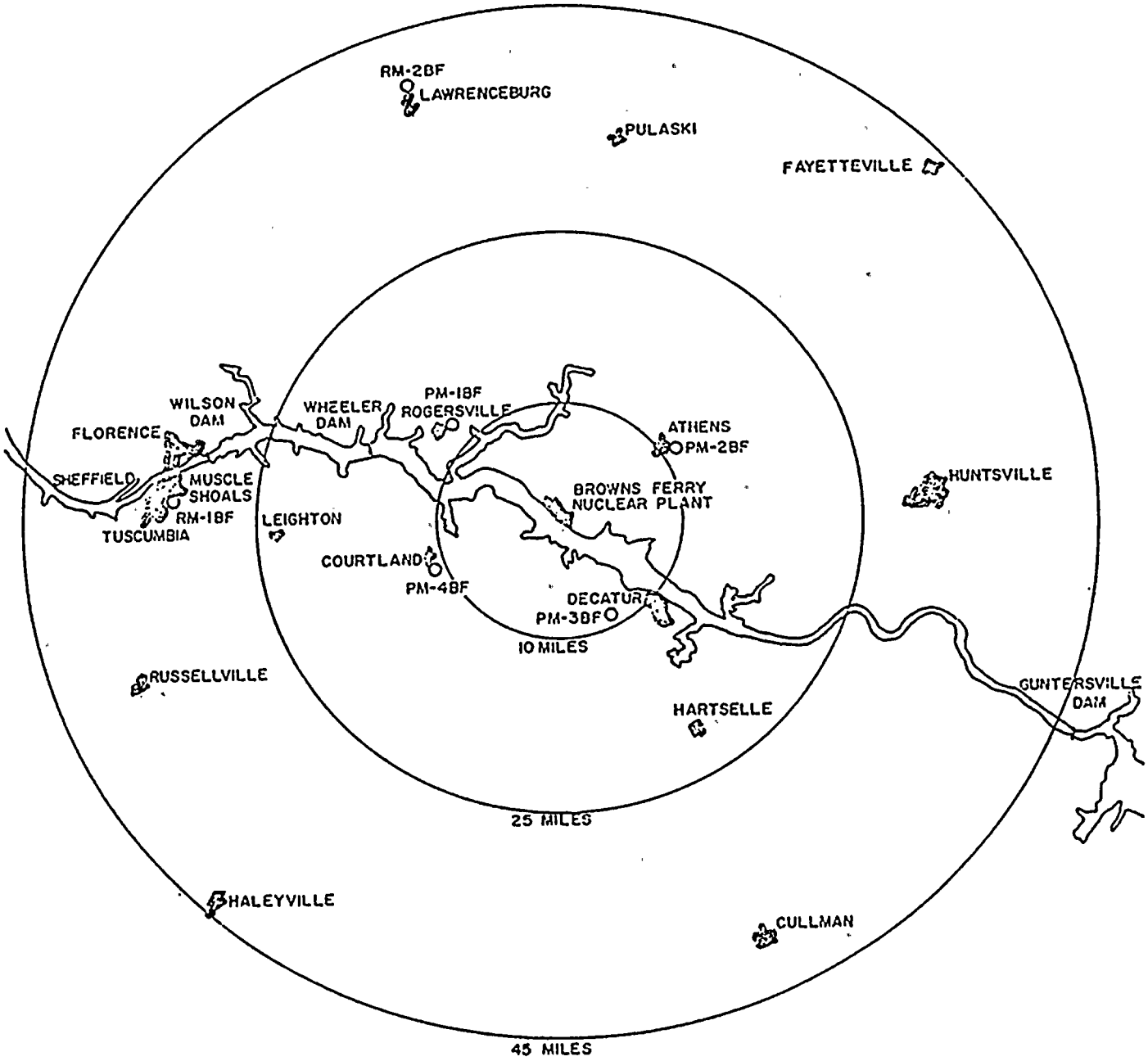


Figure 4.2-2

Browns Ferry Nuclear Plant

ATMOSPHERIC AND TERRESTRIAL MONITORING NETWORK



O-ENVIRONMENTAL MONITORING STATION

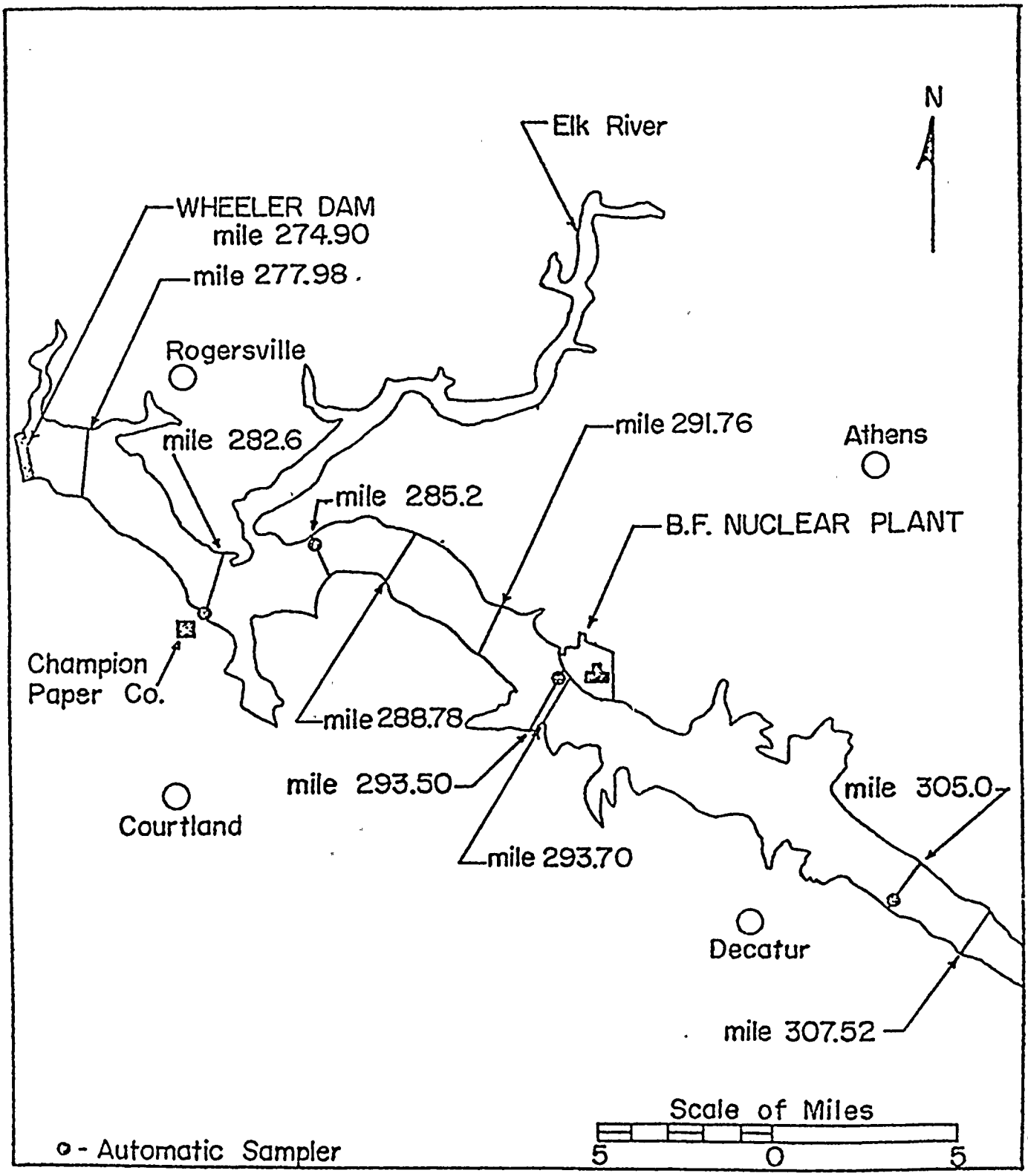
NOTE: THE FOLLOWING SAMPLES ARE COLLECTED FROM EACH STATION:

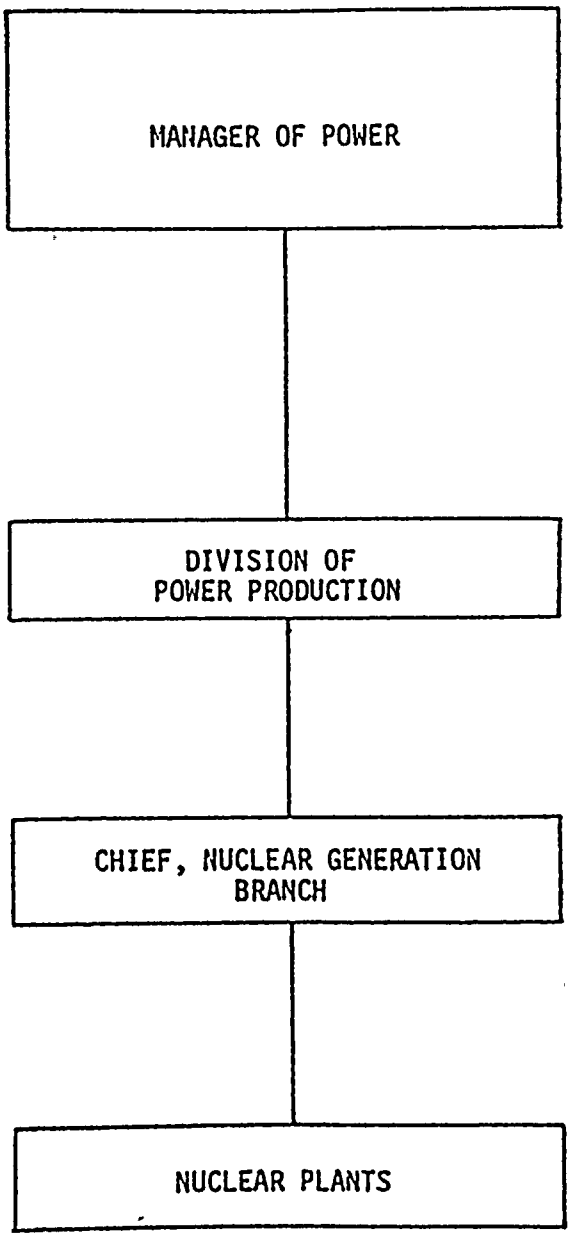
AIR PARTICULATES	RAINWATER
RADIOIODINE	SOIL
HEAVY PARTICLE FALLOUT	VEGETATION

Figure 4.2-3

Browns Ferry Nuclear Plant

RESERVOIR MONITORING NETWORK

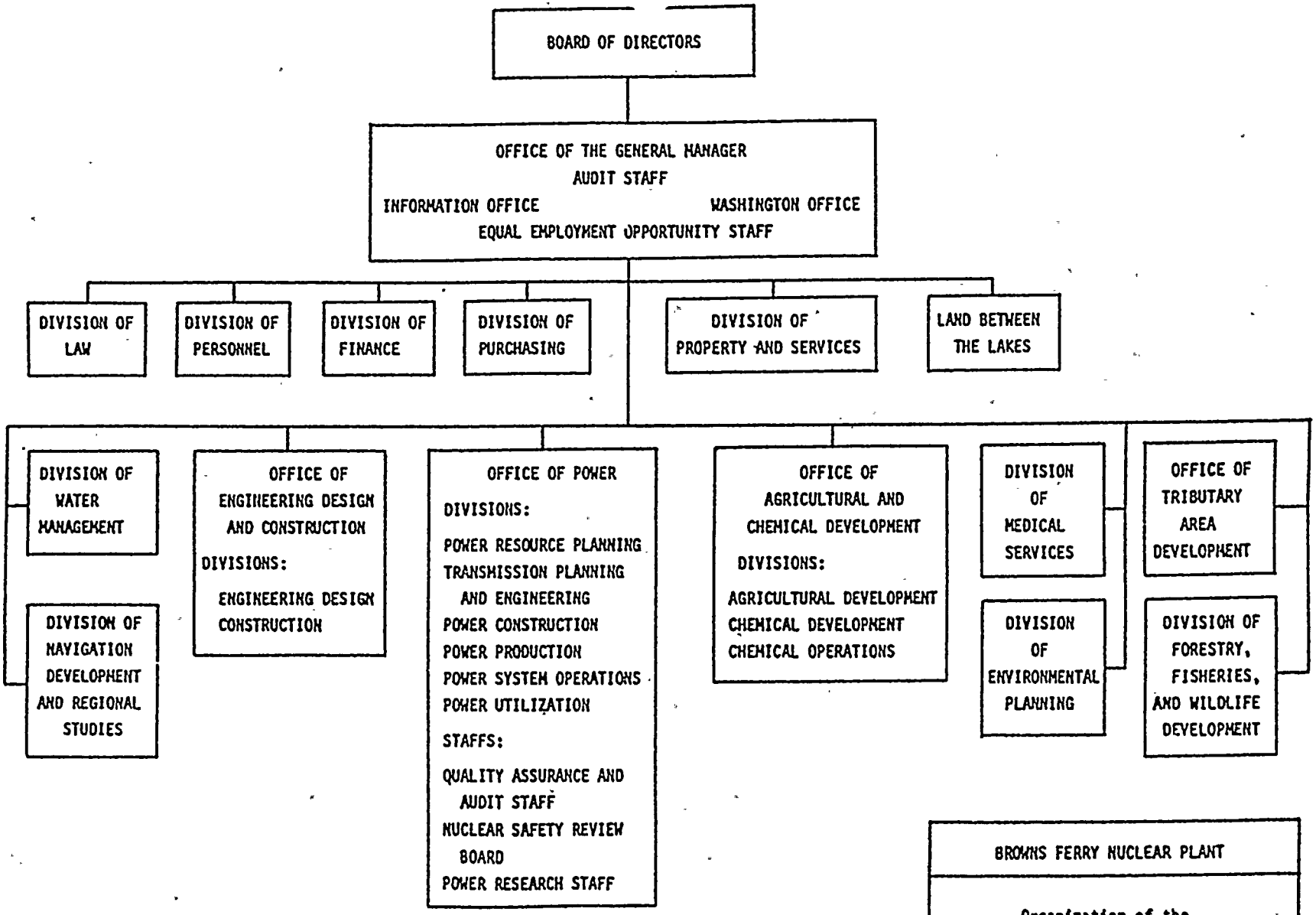




BROWNS FERRY NUCLEAR PLANT

TVA Office of Power Organization for Operation of Nuclear Plants

Figure 5.2-1



BROWNS FERRY NUCLEAR PLANT

Organization of the Tennessee Valley Authority

Figure 5.2-2