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

May 14, 1986

Docket No. 50-219

Mr. P. B. Fiedler
Vice President and Director
Oyster Creek Nuclear Generating Station
Post Office Box 388
Forked River, New Jersey 08731

Dear Mr. Fiedler:

SUBJECT: RETYPED APPENDIX A TECHNICAL SPECIFICATIONS (TAC 60578) "See Tech. Spec's"

Re: Oyster Creek Nuclear Generating Station

In the December 1985 Progress Review Meeting (Summary dated February 12, 1986), the staff's Project Manager for Oyster Creek stated that the staff was having your Appendix A Technical Specifications (TS) retyped. The reason for this was that for a number of your past licensing actions we have had to retype complete pages of the TS before issuing the action and your TS is a collection of several different size paper, formats and typing styles.

Enclosed is the retyped TS for Oyster Creek. This document has been proofread by the staff and its contractor; however, we request that you review this document and provide us with any corrections you believe are needed before this document is issued as the official TS for Oyster Creek. This document is complete up to Amendment 101, Diesel Fire Pump Battery System, dated March 31, 1986. This document is strictly a retyping word-for-word of the existing TS up to Amendment 101 except that three corrections have been made to the Bases. For the Bases, in two cases, a misspelled word was spelled correctly, and, in one case, one word was deleted where it had been repeated twice.

The retyped TS include the references in the existing TS to the Oyster Creek Facility Description and Safety Analysis Report instead of your Updated Final Safety Analysis Report (FSAR). This is in Section 5 and the Bases to the TS. You should submit changes to the TS to have the TS reference only the FSAR. These changes should be submitted on a schedule to be negotiated with the NRC Project Manager so that they can be issued with the Full Term Operating License (FTOL) TS.

The retyped TS also includes copies of the figures in the existing TS. These figures need to be redrawn. We request that you provide new originals for these figures on a schedule also to be negotiated with the NRC Project Manager so that they can be issued with the FTOL TS.

The references on the Bases for Section 5.3, Auxiliary Equipment, contains two reference 6. We believe that the second reference should be deleted. You are requested to confirm this.

I request that you provide us by July 15, 1986, with your corrections to this document and your certification that this document with the corrections is the Appendix A Technical Specifications for Oyster Creek. This will allow the staff to issue this retyped TS as soon as reasonably possible to reduce the time that the staff is keeping two TS up-to-date. The retyped TS will be issued incorporating the latest Amendments including those issued after Amendment 101. You may add these future amendments to the corrections you submit to the staff.

Until the retyped TS are issued by the staff as the official TS for Oyster Creek, the official TS for Oyster Creek are the existing TS.

Sincerely,

Jack N. Donohew, Jr., Project Manager
BWR Project Directorate #1
Division of BWR Licensing

Enclosures:
Retyped Oyster Creek

Appendix A Technical Specifications

cc w/enclosures:
See next page

DISTRIBUTION W/ENCLOSURE
Docket
NRC PDR
Local PDR
JDonohew
Service List

DISTRIBUTION W/O ENCLOSURE
BWD#1 Reading
RBernero
EJordan
BGrimes
JPartlow
CJamerson
JZwolinski
ACRS (10)
OELD
CMiles
TBarnhart

DBL:PD#1
CJamerson
5/13/86

DBL:PD#1
JDonohew:tm
5/14/86

DBL:PD#1
JZwolinski
5/14/86

Mr. P. B. Fiedler
Oyster Creek Nuclear Generating Station

Oyster Creek Nuclear
Generating Station

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Docket No. 50-219

APPENDIX A
TO PROVISIONAL OPERATING LICENSE DPR-16*
TECHNICAL SPECIFICATIONS

AND BASES

for

OYSTER CREEK NUCLEAR POWER PLANT

UNIT NO. 1

OCEAN COUNTY, NEW JERSEY

Jersey Central Power & Light Company

GPU Nuclear Corporation

*Per Errata Sheet dated 4-9-69

TABLE OF CONTENTS

TABLE OF CONTENTS (cont'd)

TABLE OF CONTENTS (cont'd)

Issued by NRC Order dated 10-24-80

SECTION I

DEFINITIONS

The following frequently used terms are defined to aid in the uniform interpretation of the specifications.

1.1 OPERABLE-OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electrical power sources, cooling of seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

1.2 OPERATING

Operating means that a system or component is performing its required function.

1.3 POWER OPERATION

Power operation is any operation when the reactor is in the startup mode or run mode except when primary containment integrity is not required.

1.4 STARTUP MODE

The reactor is in the startup mode when the reactor mode switch is in the startup mode position. In this mode, the reactor protection system scram trips initiated by condenser low vacuum and main steam line isolation valve closure are bypassed when reactor pressure is less than 600 psig; the low pressure main steamline isolation valve closure is bypassed; the IRM trips for rod block and scram are operable; and the SRM trips for rod block are operable.

1.5 RUN MODE

The reactor is in the run mode when the reactor mode switch is in the run mode position. In this mode, the reactor protection system is energized with APRM protection and the control rod withdrawal interlocks are in service.

1.6 SHUTDOWN CONDITION

The reactor is in a shutdown condition when the reactor mode switch is in the shutdown mode position and there is fuel in the reactor vessel. In this condition, the reactor is subcritical, a control rod block is initiated, all operable control rods are fully inserted, and specification 3.2-A is met.

1.7 COLD SHUTDOWN

The reactor is at cold shutdown when the mode switch is in the shutdown mode position, there is fuel in the reactor vessel, all operable control rods are fully inserted, and the reactor coolant system maintained at less than 212°F and vented.

1.8 PLACE IN SHUTDOWN CONDITION

Proceed with and maintain an uninterrupted normal plant shutdown operation until the shutdown condition is met.

1.9 PLACE IN COLD SHUTDOWN CONDITION

Proceed with and maintain an uninterrupted normal plant shutdown operation until the cold shutdown condition is met.

1.10 PLACE IN ISOLATED CONDITION

Proceed with and maintain an uninterrupted normal isolation of the reactor from the turbine condenser system including closure of the main steam isolation valves.

1.11 REFUEL MODE

The reactor is in the refuel mode when the reactor mode switch is in the refuel mode position and there is fuel in the reactor vessel. In this mode the refueling platform interlocks are in operation.

1.12 REFUELING OUTAGE

For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled refueling outage; however, where such outages occur within 8 months of the end of the previous refueling outage, the test or surveillance need not be performed until the next regularly scheduled outage. Following the first refueling outage, the time between successive tests or surveillance shall not exceed 20 months.*

1.13 PRIMARY CONTAINMENT INTEGRITY

Primary containment integrity means that the drywell and adsorption chamber are closed and all of the following conditions are satisfied:

A. All non-automatic primary containment isolation valves which are not required to be open for plant operation are closed.

B. At least one door in the airlock is closed and sealed.

C. All automatic containment isolation valves specified in Table 3.5.2 are operable or are secured in the closed position.

D. All blind flanges and manways are closed.

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*The time between successive tests or surveillances shall not exceed 30 months prior to the cycle 10 refueling outage only.

1.14 SECONDARY CONTAINMENT INTEGRITY

Secondary containment integrity means that the reactor building is closed and the following conditions are met:

A. At least one door at each access opening is closed.

B. The standby gas treatment system is operable.

C. All reactor building ventilation system automatic isolation valves are operable or are secured in the closed position.

1.15 (DELETED)

1.16 RATED FLUX

Rated flux is the neutron flux that corresponds to a steady state power level of 1930 MW(t). Use of the term 100 percent also refers to the 1930 thermal megawatt power level.

1.17 REACTOR THERMAL POWER-TO-WATER

Reactor thermal power-to-water is the sum of (1) the instantaneous integral over the entire fuel clad outer surface of the product of heat transfer area increment and position dependent heat flux and (2) the instantaneous rate of energy deposition by neutron and gamma reactions in all the water and core components except fuel rods in the cylindrical volume defined by the active core height and the inner surface of the core shroud.

1.18 PROTECTIVE INSTRUMENTATION LOGIC DEFINITIONS

A. Instrument Channel

An instrument channel means an arrangement of a sensor and auxiliary equipment required to generate and transmit to a trip system a single trip signal related to the plant parameter monitored by that instrument channel.

B. 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 (e.g., initiation of a core spray loop, a containment spray loop, automatic depressurization, isolation of an isolation condenser, offgas system isolation, reactor building isolation, standby gas treatment and rod block) or the coincident tripping of two trip systems (e.g., initiation of scram, isolation condenser, reactor isolation, and primary containment isolation).

1.19 INSTRUMENTATION OF SURVEILLANCE DEFINITIONS

A. Channel Check

A qualitative determination of acceptable operability by observation of channel behavior during operation. This determination shall include, where possible, comparison of the channel with other independent channels measuring the same variable.

B. Channel Test

Injection of a simulated signal into the channel to verify its proper response including, where applicable, alarm and/or trip initiating action.

C. Channel Calibration

Adjustment of channel output such that it responds, with acceptable range and accuracy, to known values of the parameter which the channel measures. Calibration shall encompass the entire channel, including equipment actuation, alarm or trip.

1.20 FDSAR

Oyster Creek Unit No. 1 Facility Description and Safety Analysis Report as amended by revised pages and figure changes contained in Amendments 14, 31 and 45.*

1.21 CORE ALTERATION

A core alteration is the addition, removal, relocation or other manual movement of fuel or controls in the reactor core. Control rod movement with the control rod drive hydraulic system is not defined as a core alteration.

1.22 MINIMUM CRITICAL POWER RATIO

The minimum critical power ratio is the ratio of that power in a fuel assembly which is calculated to cause some point in that assembly to experience boiling transition to the actual assembly operating power.

1.23 STAGGERED TEST BASIS

A Staggered Test Basis shall consist of:

A. A test schedule for n systems, subsystems, trains or other designated components obtained by dividing the specified test interval into n equal subintervals.

B. The testing of one system, subsystem, train or other designated component at the beginning of each subinterval.

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*Per Errata dtd. 4-9-69

1.24 SURVEILLANCE REQUIREMENTS

Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within the safety limits, and that the limiting conditions of operation will be met. Each surveillance requirement shall be performed within the specified time interval with:

*A. A maximum allowable extension not to exceed 25% of the surveillance interval,

*B. A total maximum combined interval time for any 3 consecutive surveillance intervals not to exceed 3.25 times the specified surveillance interval.

Surveillance requirements for systems and components are applicable only during the modes of operation for which the systems or components are required to be operable, unless otherwise stated in the specification.

1.25 FIRE SUPPRESSION WATER SYSTEM

A FIRE SUPPRESSION WATER SYSTEM shall consist of: a water source; pump; and distribution piping with associated sectionalizing control or isolation valves. Such valves shall include yard hydrant curb valves, and the first valve ahead of the water flow alarm device on each sprinkler, hose standpipe or spray system riser.

1.26 FRACTION OF LIMITING POWER DENSITY (FLPD)

The fraction of limiting power density is the ratio of the linear heat generation rate (LHGR) existing at a given location to the design LHGR for that bundle type.

1.27 MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)

The maximum fraction of limiting power density is the highest value existing in the core of the fraction of limiting power density (FLPD).

1.28 FRACTION OF RATED POWER (FRP)

The fraction of rated power is the ratio of core thermal power to rated thermal power.

1.29 TOP OF ACTIVE FUEL (TAF) - 353.3 inches above vessel zero.

1.30 REPORTABLE EVENT

A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

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*Not applicable to containment leak rate test.

1.31 IDENTIFIED LEAKAGE

IDENTIFIED LEAKAGE is that leakage which is collected in the primary containment equipment drain tank and eventually transferred to radwaste for processing.

1.32 UNIDENTIFIED LEAKAGE

UNIDENTIFIED LEAKAGE is all measured leakage that is other than identified leakage.

SECTION 2

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMIT - FUEL CLADDING INTEGRITY

Applicability: Applies to the interrelated variables associated with fuel thermal behavior.

Objective: To establish limits on the important thermal hydraulic variables to assure the integrity of the fuel cladding.

Specifications:

A. When the reactor pressure is greater than or equal to 800 psia and the core flow is greater than or equal to 10% of rated, the existence of a minimum critical power ratio (MCPR) less than 1.07 shall constitute violation of the fuel cladding integrity safety limit.

B. When the reactor pressure is less than 800 psia or the core flow is less than 10% of rated, the core thermal power shall not exceed 25% of rated thermal power.

C. In the event that reactor parameters exceed the limiting safety system settings in specification 2.3 and a reactor scram is not initiated by the associated protective instrumentation, the reactor shall be brought to, and remain in, the cold shutdown condition until an analysis is performed to determine whether the safety limit established in specification 2.1.A and 2.1.B was exceeded.

D. During all modes of reactor operation with irradiated fuel in the reactor vessel, the water level shall not be less than 4'8" above the top of active fuel.

E. During all modes of operation except when the reactor head is off and the reactor is flooded to a level above the main steam nozzles, at least two [2] recirculation loop suction valves and their associated discharge valves will be in the full open position.

Bases:

The fuel cladding integrity safety limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedure used to calculate the

critical power result in an uncertainty in the value of the critical power. Therefore the fuel cladding integrity safety limit is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition considering the power distribution within the core and all uncertainties.

The Safety Limit MCPR is determined using the General Electric Thermal Analysis Basis, GETAB[1], which is a statistical model that combines all of the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the General Electric Critical Quality (X) - Boiling Length (L), GEXL, correlation.

The use of the GEXL correlation is not valid for the critical power calculations at pressures below 800 psia or core flows less than 10% of rated. Therefore, the fuel cladding integrity safety limit is protected by limiting the core thermal power.

At pressures below 800 psia, the core elevation pressure drop (0 power, 0 flow) is greater than 4.56 psi. At low power and all 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 power and all flows will always be greater than 4.56 psi. Analyses show that with a flow of 28×10^3 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 28×10^3 lbs/hr irrespective of total core flow and independent of bundle power for the range of bundle powers of concern. 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 psi or core flow less than 10% is conservative.

Plant safety analyses have shown that the scrams caused by exceeding any safety setting will assure that the Safety Limit of Specification 2.1.A or 2.1.B will not be exceeded. Scram times are checked periodically to assure the insertion times are adequate. The thermal power transient resulting when a scram is accomplished other than by the expected scram signal (e.g., scram from neutron flux following closure of the main turbine stop valves) does not necessarily cause fuel damage. Specification 2.1.C requires that appropriate analysis be performed to verify that backup protective instrumentation has prevented exceeding the fuel cladding integrity safety limit prior to resumption of power operation. The concept of not approaching a Safety Limit provided scram signals are operable is supported by the extensive plant safety analysis.

If reactor water level should drop below the top of the active fuel, the ability to cool the core is reduced. This reduction in core

cooling capability could lead to elevated cladding temperatures and clad perforation. With a water level above the top of the active fuel, adequate cooling is maintained and the decay heat can easily be accommodated. It should be noted that during power generation there is no clearly defined water level inside the shroud and what actually exists is a mixture level. This mixture begins within the active fuel region and extends up through the moisture separators. For the purpose of this specification water level is defined to include mixture level during power operations.

The lowest point at which the water level can presently be monitored is 4'8" below the top of active fuel. Although the lowest reactor water level limit which ensures adequate core cooling is the top of the active fuel, the safety limit has been conservatively established at 4'8" above the top of active fuel.

Specification 2.1.E assures that an adequate flow path exists from the annular space, between the pressure vessel wall and the core shroud, to the core region. This provides for good communication between these areas, thus assuring that reactor water level instrument readings are indicative of the water level in the core region.

REFERENCES

(1) NEDO-24195, General Electric Reload Fuel Application for Oyster Creek.

2.2 SAFETY LIMIT - REACTOR COOLANT SYSTEM PRESSURE

Applicability: Applies to the limit on reactor coolant system pressure.

Objective: Preserve the integrity of the reactor coolant system.

Specification: The reactor coolant system pressure shall not exceed 1375 psig whenever irradiated fuel is in the reactor vessel.

Bases:

The reactor coolant system(1) represents an important barrier in the prevention of the uncontrolled release of fission products. It is essential that the integrity of this system be protected by establishing a pressure limit to be observed whenever there is irradiated fuel in the reactor vessel.

The pressure safety limit of 1375 psig was derived from the design pressures of the reactor pressure vessel, coolant piping, and isolation condenser. The respective design pressures are 1250 psig at 575°F, 1200 psig at 570°F and 1250 psig at 575°F. The pressure safety limit was chosen as the lower of the pressure transients permitted by the applicable design codes: ASME Boiler and Pressure Vessel Code Section I for the pressure vessel, ASME Boiler and Pressure Vessel Code Section III for the isolation condenser and the ASA Piping Code Section B31.1 for the reactor coolant system piping. The ASME Code permits pressure transients up to 10% over the design pressure (110% x 1250 = 1275 psig) and the ASA Code permits pressure transients up to 15% over the design pressure (115% x 1200 = 1380 psig).

The design basis for the reactor pressure vessel makes evident the substantial margin of protection against failure at the safety pressure limit of 1375 psig. The vessel has been designed for a general membrane stress no greater than 20,000 psi at an internal pressure of 1250 psig and temperature of 575°F; this is more than a factor of 2 below the yield strength of 42,300 psi at this temperature. At the pressure limit of 1375 psig, the general membrane stress increases to 22,000 psi, still almost a factor of 2 below the yield strength. The reactor coolant system piping provides a comparable margin of protection at the established pressure safety limit.

The normal operating pressure of the reactor coolant system is 1020 psig. An overpressurization analysis (2) is peformed each cycle to assure the pressure safety limit is not exceeded. The reactor fuel cladding can withstand pressures up to the safety limit, 1375 psig, without collapsing.(3) Finally, reactor system pressure is continuously monitored in the control room during reactor operation.

REFERENCES

(1) FDSAR, Volume I, Section IV.
(2) NEDO-24195, General Electric Reload Fuel Application for Oyster Creek.
(3) FDSAR, Volume I, Section III-2.3.3

2.3 LIMITING SAFETY SYSTEM SETTINGS

Applicability: Applies to trip settings on automatic protective devices related to variables on which safety limits have been placed.

Objective: To provide automatic corrective action to prevent the safety limits from being exceeded.

Specification: Limiting safety system settings shall be as follows:

FUNCTION	LIMITING SAFETY SYSTEM SETTINGS
A. Neutron Flux, Scram	
A.1 APRM	When the reactor mode switch is in the Run position, the APRM flux scram setting shall be $S \leq [(1.34 \times 10^{-6})\ W + 34.0]\ [\frac{FRP}{MFLPD}]$ with a maximum setpoint of 115.7% for core flow equal to 61×10^{6} lb/hr and greater, where: S = setting in percent of rated power; W = recirculation flow (lb/hr); FRP = fraction of rated thermal power is the ratio of core thermal power to rated thermal power; MFLPD = maximum fraction of limiting power density where the limiting power density for each bundle is the design linear heat generation rate for that bundle. The ratio of FRP/MFLPD shall be set equal to 1.0 unless the actual operating value is less than 1.0 in which case the actual operating value will be used. This adjustment may be accomplished by increasing the APRM gain and thus reducing the flow reference APRM High Flux Scram Curve by the reciprocal of the APRM gain change.
A.2 IRM	$\leq$ 38.4 percent of rated neutron flux

FUNCTION	LIMITING SAFETY SYSTEM SETTINGS
B. Neutron Flux, Control Rod Block	The Rod Block setting shall be $S \leq [(1.34 \times 10^{-6})\ W + 24.3]\ [\frac{FRP}{MFLPD}]$ with a maximum setpoint of 106% for core flow equal to 61×10^{6} lb/hr and greater. The definitions of S, W, FRP and MFLPD used above for the APRM scram trip apply. The ratio of FRP to MFLPD shall be set equal to 1.0 unless the actual operating value is less than 1.0, in which case the actual operating value will be used. This adjustment may be accomplished by increasing the APRM gain and thus reducing the flow referenced APRM rod block curve by the reciprocal of the APRM gain change.
C. Reactor High, Pressure, Scram	$\leq$1060 psig
D. Reactor High Pressure, Relief Valves Initiation	2 @ $\leq$ 1070 psig 3 @ $\leq$ 1090 psig
E. Reactor High Pressure, Isolation Condenser Initiation	$\leq$1060 psig with time delay $\leq$3 seconds
F. Reactor High Pressure, Safety Valve Initiation	4 @ 1212 psig 4 @ 1221 psig ± 12 psi 4 @ 1230 psig 4 @ 1239 psig
G. Low Pressure Main Steam Line, MSIV Closure	$\geq$825 psig (initiated in IRM range 10)
H. Main Steam Line Isolation Valve Closure, Scram	$\leq$10% Valve Closure from full open
I. Reactor Low Water Level, Scram	$\geq$11'5" above the top of the active fuel as indicated under normal normal operating conditions
J. Reactor Low-Low Water Level, Main Steam Line Isolation Valve Closure	$\geq$7'2" above the top of the active fuel as indicated under normal operating conditions

	FUNCTION	LIMITING SAFETY SYSTEM SETTINGS
K.	Reactor Low-Low Water Level, Core Spray Initiation	≥7'2" above the top of the active fuel
L.	Reactor Low-Low Water Level, Isolation Condenser Initiation	≥7'2" above the top of the active fuel with time delay ≤3 seconds
M.	Turbine Trip, Scram	10 percent turbine stop valve(s) closure from full open
N.	Generator Load Rejection, Scram	Initiate upon loss of oil pressure from turbine acceleration relay
O.	Recirculation Flow, Scram	≤71.4 Mlb/hr (117% of rated flow)
P.	Loss of Power	
	1) 4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	0 volts with 3 seconds ± 0.5 seconds time delay
	2) 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	3671 ± 1% (36.7) volts 10 ±10% (1.0) second time delay

Bases:

Safety limits have been established in Specifications 2.1 and 2.2 to protect the integrity of the fuel cladding and reactor coolant system barriers, respectively. Automatic protective devices have been provided in the plant design for corrective actions to prevent the safety limits from being exceeded in normal operation or operational transients caused by reasonably expected single operator error or equipment malfunction. This Specification establishes the trip settings for these automatic protection devices.

The Average Power Range Monitor, APRM[1], trip setting has been established to assure never reaching the fuel cladding integrity safety limit. The APRM system responds to changes in neutron flux. However, near the rated thermal power, the APRM is calibrated using a plant heat balance, so that the neutron flux that is sensed is read out as percent of the rated thermal power. For slow maneuvers, such as those where core thermal power, surface heat flux, and the power transferred to the water follow the neutron flux, the APRM will read reactor thermal power. For fast transients, the neutron flux will lead the power transferred from the cladding to the water due to the effect of the fuel time constant. Therefore, when the neutron flux increases to the scram setting, the percent increase in heat flux and power transferred to the water will be less than the percent increase in neutron flux.

The APRM trip setting will be varied automatically with recirculation flow, with the trip setting at the rated flow of 61.0 x 10^6 lb/hr or greater being 115.7% of rated neutron flux. Based on a complete evaluation of the reactor dynamic performance during normal operation as well as expected maneuvers and the various mechanical failures, it was concluded that sufficient protection

is provided by the simple fixed scram setting (2,3). However, in response to expressed beliefs (4) that variation of APRM flux scram with recirculation flow is a prudent measure to ensure safe plant operation, the scram setting will be varied with recirculation flow.

An increase in the APRM scram trip setting would decrease the margin present before the fuel cladding integrity safety limit is reached. The APRM scram trip 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 scram trip setting was selected because it provides adequate margin for the fuel cladding integrity safety limit and yet allows operating margin that reduces the possiblity of unnecessary scrams.

The scram trip setting must be adjusted to ensure that the LHGR transient peak is not increased for any combination of maximum fraction of limiting power density (MFLPD) and reactor core thermal power. The scram setting is adjusted in accordance with the formula in Specification 2.3.A, when the MFLPD is greater than the fraction of the rated power (FRP). The adjustment may be accomplished by increasing the APRM gain and thus reducing the flow referenced APRM High Flux Scram Curve by the reciprocal of the APRM gain change.

For operation in the Startup mode while the reactor is at low pressure, the IRM range 9 High Flux scram setting of 12% of the rated power provides adequate thermal margin between the maximum power and the safety limit of 18.3% of rated power to accommodate anticipated maneuvers associated with power plant startup. There are a few possible sources of rapid reactivity input to the system in the low power/low flow condition. Effects of increasing pressure at zero or low void content are minor, because cold water from sources available during the startup is not much colder than that already in the system, temperature coefficients are small, and control rod sequences are constrained by operating procedures backed up by the rod worth minimizer. Worth of individual rods is very low in a constrained rod pattern. In a sequenced rod withdrawal approach to the scram level, the rate of power rise is no more than five percent of the rated per minute, and the IRM system would be more than adequate to assure a scram before the power could exceed the safety limit.

To continue operation beyond 12% of rated power, the IRMs must be transferred into range 10. The Reactor Protection System is designed such that reactor pressure must be above 825 psig to successfully transfer the IRMs into range 10, thus assuring protection for the fuel cladding safety limit. The IRM scram remains active until the mode switch is placed in the RUN position at which time the trip becomes a coincident IRM upscale, APRM downscale scram.

The adequacy of the IRM scram was determined by comparing the scram level on the IRM range 10 to the scram level on the APRMs at 30% of rated flow. The IRM scram is at 38.4% of rated power while the APRM scram is at 52.7% of rated power. The minimum flow for Oyster Creek is at 30% of rated power and this would be the lowest APRM scram point. The increased recirculation flow to 65% of flow will provide additional margin to CPR limits. The APRM scram at 65% of rate flow is 87.1% of rated power, while the IRM range 10 scram remains at 38.4% of rated power. Therefore, transients requiring a scram based on flux excursion will be terminated sooner with a IRM range 10 scram than with an

APRM scram. The transients requiring a scram by nuclear instrumentation are the loss of feedwater heating and the improper startup of an idle circulation loop. The loss of feedwater heating transient is not affected by the range 10 IRM since the feedwater heaters will not be put into service until after the LPRM downscales have cleared, thus insuring the operability of the APRM system. This will be administratively controlled. The improper startup of an idle circulation loop becomes less severe at lower power level and the IRM scram would be adequate to terminate the flux excursion.

The Rod Worth Minimizer is not required beyond 10% of rated power. The ability of the IRMs to terminate a rod withdrawal transient is limited due to the number and location of IRM detectors. An evaluation was performed that showed by maintaining a minimum recirculation flow of 39.65×10^6 lb/hr in range 10 a complete rod withdrawal initiated at 35% of rated power or less would not result in violating the fuel cladding safety limit. Therefore, a rod block on the IRMs at less than 35% of rated power would be adequate protection against a rod withdrawal transient.

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 gross rod withdrawal at constant recirculation flow rate to protect against grossly exceeding the MCPR Fuel Cladding Integrity Safety Limit. This rod block trip setting, which is automatically varied with recirculation loop flow rate, prevents an increase in the reactor power level to excessive 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 106% of the 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 incore LPRM system. As with APRM scram trip setting, the APRM rod block trip setting is adjusted downward if the maximum fraction of limiting power density exceeds the fraction of the rated power, thus preserving the APRM rod block safety margin. As with the scram setting, this may be accomplished by adjusting the APRM gains.

The settings on the reactor high pressure scram, anticipatory scrams, reactor coolant system relief valves and isolation condenser have been established to assure never reaching the reactor coolant system pressure safety limit as well as assuring the system pressure does not exceed the range of the fuel cladding integrity safety limit. In addition, the APRM neutron flux scram and the turbine bypass system also provide protection for these safety limits, e.g., turbine trip and loss of electrical load transients (5). In addition to preventing power operation above 1060 psig, the pressure scram backs up the other scrams for these transients and other steam line isolation type transients. Actuation of the isolation condenser during these transients removes the reactor decay heat without further loss of reactor coolant thus protecting the reactor water level safety limit.

The reactor coolant system safety valves offer yet another protective feature for the reactor coolant system pressure safety limit since these valves are sized assuming no credit for other pressure relieving devices. In compliance with Section I of the ASME Boiler and Pressure Vessel Code, the safety valve must be set to open at a pressure no higher than 103% of design pressure, and they must limit the reactor pressure to no more than 110% of design pressure. The safety valves are sized according to the Code for a condition of turbine stop valve closure while operating at 1930 MWt, followed by [1] a delay of all scrams, [2] failure of the turbine bypass valves to open, and [3] failure of the isolation condensers and relief valves to operate. Under these conditions, a total of 16 safety valves are required to turn the pressure transient. The ASME B&PV Code allows a ±1% of working pressure (1250 psig) variation in the lift point of the valves. This variation is recognized in Specification 4.3.

The low pressure isolation of the main steam lines at 825 psig was provided to give protection against fast reactor depressurization and the resulting rapid cool-down of the vessel. Advantage was taken of the scram feature which 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 and the IRMs be in the range 9, or lower, where protection of the fuel cladding integrity safety limit is provided by the IRM high neutron flux scram. Thus, the combination of main steam line low pressure isolation and isolation valves 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 which occur during normal or inadvertent isolation valve closure.

The low water level trip setting of 11'5" above the top of the active fuel has been established to assure that the reactor is not operated at a water level below that for which the fuel cladding integrity safety limit is applicable. With the scram set at this point, the generation of steam, and thus the loss of inventory, is stopped. For example, for a loss of feedwater flow a reactor scram at the value indicated and isolation valve closure at the low-low water level set point results in more than 4 feet of water remaining above the core after isolation (6).

During periods when the reactor is shut down, decay heat is present and adequate water level must be maintained to provide core cooling. Thus, the low-low level trip point of 7'2" above the core is provided to actuate the core spray system to provide cooling water should the level drop to this point. In addition, the normal reactor feedwater system and control rod drive hydraulic system provide protection for the water level safety limit both when the reactor is operating at power and in the shutdown condition.

The turbine stop valve(s) scram is provided to anticipate the pressure, neutron flux, and heat flux increase caused by the rapid closure of the turbine stop valve(s) and failure of the turbine bypass system.

The generator load rejection scram is provided to anticipate the rapid increase in pressure and neutron flux resulting from fast closure of the turbine control

valves to a load rejection and failure of the turbine bypass system. This scram is initiated by the loss of turbine acceleration relay oil pressure. The timing for this scram is almost identical to the turbine trip.

The total recirculation flow scram is provided to terminate a flow increase transient. Flow transients are normally protected against by employing the k_f factor and using mechanical stops on the recirculation pumps. Oyster Creek does not have mechanical stops on its recirculation pumps and maximum flow is beyond the limit for which the k_f factor provides protection. The recirculation flow scram is set to the maximum flow level corresponding to the k_f curve to be used (Section 3.10).

The undervoltage protection system is a 2 out of 3 coincident logic relay system designated to shift emergency buses C and D to on site power should normal power be lost or degraded to an unacceptable level. The trip points and time delay settings have been selected to assure an adequate power source to emergency safeguards systems in the event of a total loss of normal power or degraded conditions which would adversely affect the functioning of engineered safety features connected to the plant emergency power distribution system.

References

(1) FDSAR, Volume I, Section VII-4.2.4.2
(2) FDSAR, Amendment 28, Item III.A-12
(3) FDSAR, Amendment 32, Question 13
(4) Letters, Peter A. Morris, Director, Division of Reactor Licensing, USAEC to John E. Logan, Vice President, Jersey Central Power and Light Company, dated November 22, 1967 and January 9, 1968
(5) FDSAR, Amendment 65, Section B.XI.
(6) FDSAR, Amendment 65, Section B.IX.

SECTION 3

LIMITING CONDITIONS FOR OPERATION

3.0 LIMITING CONDITIONS FOR OPERATION (GENERAL)

Applicability: Applies to all Limiting Conditions for Operation.

Objective: To preserve the single failure criterion for safety systems.

Specifications: A. In the event Limiting Conditions for Operation (LCOs) and/or associated action requirements cannot be satisfied because of circumstances in excess of those addressed in the specification, the unit shall be placed in COLD SHUTDOWN within the following 30 hours unless corrective measures are completed that permit operation under the permissible action statements for the specified time interval as measured from initial discovery or until the reactor is placed in a condition in which the specification is not applicable. Exceptions to the requirements shall be stated in the individual specifications.

B. When a system, subsystem, train, component or device is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may be considered OPERABLE for the purpose of satisfying the requirements of applicable LCOs., provided (1) its corresponding normal or emergency power source is OPERABLE; and (2) all of its redundant system(s), subsystem(s), train(s), component(s) and device(s) are OPERABLE, or likewise satisfy the requirements of this specification. Unless both conditions (1) and (2) are satisfied, the unit shall be placed in COLD SHUTDOWN within the following 30 hours or within the time specified in the applicable specification. This specification is not applicable in COLD SHUTDOWN or the REFUEL MODE.

Bases: Specification 3.0.A delineates the action to be taken for circumstances not directly provided for in the system LCOs and whose occurrence would violate the intent of the specification.

Specification 3.0.B delineates what additional conditions must be satisfied to permit operation to continue, consistent with the specifications for power sources, when a normal or emergency power source is not operable. It allows operation to be governed by the time limits of the specifications associated with the LCOs for the normal or emergency power source, not the individual specifications for each system, subsystem, train, component or device that is determined to be inoperable solely because of the inoperability of its normal or emergency power source. In addition, it specifically prohibits operation when one division is inoperable because its normal or emergency power source is inoperable and a safety subsystem, train, component, or device in another division is inoperable for another reason.

3.1 PROTECTIVE INSTRUMENTATION

Applicability: Applies to the operating status of plant instrumentation which performs a protective function.

Objective: To assure the operability of protective instrumentation.

Specifications: A. The following operating requirements for plant protective instrumentation are given in Table 3.1.1:

1. The reactor mode in which a secified function must be operable including allowable bypass conditions.

2. The minimum number of operable instrument channels per operable trip system.

3. The trip settings which initiate automatic protective action.

4. The action required when the limiting conditions for operation are not satisfied.

B. 1. Failure of four chambers assigned to any one APRM shall make the APRM inoperable.

2. Failure of two chambers from one radial core location in any one APRM shall make that APRM inoperable.

C. 1. Any two (2) LPRM assemblies which are input to the APRM system and are separated in distance by less than three (3) times the control rod pitch may not contain a combination of more than three (3) inoperable detectors (i.e., APRM channel failed or bypassed, or LPRM detectors failed or bypassed) out of the four (4) detectors located in either the A and B, or the C and D levels.

2. A Travelling In-Core Probe (TIP) chamber may be used as an APRM input to meet the criteria of 3.1.B and 3.1.C.1, provided the TIP is positioned in close proximity to one of the failed LPRM's. If the criteria of 3.1.B.2 or 3.1.C.1 cannot be met, power operation may continue at up to rated power level provided a control rod withdrawal block is operating or at power levels less than 61% of rated power until the TIP can be connected, positioned and satisfactorily tested, as long as Specification 3.1.B.1 and Table 3.1.1 are satisfied.

Bases: The plant protection system automatically initiates protective functions to prevent exceeding established limits. In addition, other protective instrumentation is provided to initiate action which mitigates the consequences of accidents or terminates operator control. This specification provides the limiting conditions for operation necessary to preserve the effectiveness of these instrument systems.

Table 3.1-1 defines, for each function, the minimum number of operable instrument channels for an operable trip system for the various functions specified. There are usually two trip systems required or available for each function. The specified limiting conditions for operation apply for the indicated modes of operation. When the specified limiting condition cannot be met, the specified actions required shall be undertaken promptly to modify plant operation to the condition indicated in a normal manner. Conditions under which the specified plant instrumentation may be out-of-service are also defined in Table 3.1.1.

Except as noted in Table 3.1.1 for the auto depressurization instrumentation for channel test or calibration an inoperable trip system will be placed in the tripped condition. A tripped trip system is considered operating since by virtue of being tripped it is performing its required function. This permits the instrument channels, logic channels, and other portions in the plant protection instrumentation system to be maintained, tested and calibrated while at the same time affording the plant the same degree of protection. All sensors in the untripped trip system must be operable, except as follows:

1. The high temperature sensor system in the main steam line tunnel has eight sensors in each protection logic channel. This multiplicity of sensors serving a duplicate function permits this system to operate one year without calibration. Thus, if one of the temperature sensors causes a trip in one of the two trip systems, there are several cross checks that would verify if this were a real one. If not, this sensor could be removed from service. However, a minimum of two of eight are required to be operable and only one of the two is required to accomplish a trip in a single trip system.

2. One APRM of the four in each trip system may be bypassed without tripping the trip system if core protection is maintained. Core protection is maintained by the remaining three APRM's in each trip system as discussed in Section VII-4.2.4.2 of the FDSAR.

3. One IRM channel in each of the two trip systems may be bypassed without comprising the effectiveness of the system. There are few possible sources of rapid reactivity input to the system in the low power low flow condition. 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 operting procedures backed up by the rod worth minimizer. Worth of individual rods is very low in a uniform rod pattern. Thus, of all 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, 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 five percent of rated per minute, and three operable IRM instruments in each trip system would be more than adequate to assure a scram before the power could exceed the safety limit. In many cases, if properly located, a single operable IRM channel in each trip system would suffice.

4. When required for surveillance testing, a channel is made inoperable. In order to be able to test its trip function to the final actuating device of its trip system, the trip system cannot already be tripped by some other means such as a mode switch, interlock, or manual trip. Therefore, there will be times during the test that the channel is inoperable but not tripped. For a two channel trip system, this means that full reliance is being placed on the channel that is not being tested. The probability of the trip system failing to perform its function when required under this configuration can be made commensurate with a like probability under its normal configuration by limiting the operating time in the test mode. An acceptable test duration to meet this criterion is computed to be one hour based on the following considerations:

   (a) the increased probability of an unsafe failure for a one-out-of-one trip system in comparison to a one-out-of-two trip system;

   (b) the probability that the one channel being relied upon is itself inoperable at the beginning of the test;

   (c) the probability that an event will occur that requires the trip system to function during the time spent in the test mode;

   (d) an unsafe failure rate of 2.5×10^{-6} hr^{-1} (Sec. 4.1, p. 4.1-2) for the channel; and

   (e) a test interval (time between tests) of one month."

Bypasses of inputs to a trip system other than the IRM and APRM bypasses are provided for meeting operational requirements listed in the notes in Table 3.1.1. Note a allows the "high water level in scram discharge volume" scram trip to be bypassed in the refuel mode. In order to reset the safety system after a scram condition, it is necessary to drain the scram discharge volume to clear this scram input condition. (This condition usually follows any scram, no matter what the initial cause might have been.) In order to do this, this particular scram function can be bypassed only in the fuel position. Since all of the control rods are completely inserted following a scram, it is permissible to bypass this condition because a control rod block prevents withdrawal as long as the switch is in the bypass condition for this function.

The manual scram associated with moving the mode switch to shutdown is used merely to provide a mechanism whereby the reactor protection system scram logic channels and the reactor manual control system can be energized. The ability to reset a scram twenty (20) seconds after going into the shutdown mode provides the benefical function of relieving scram pressure from the control rod drives which will increase their expected lifetime.

To permit plant operation to generate adequate steam and pressure to establish turbine seals and condenser vacuum at relatively low reactor power, the main condenser vacuum trip is bypassed until 600 psig. This bypass also applies to the main steam isolation valves for the same reason.

The action required when the minimum instrument logic conditions are not met is chosen so as to bring plant operation promptly to such a condition that the

particular protection instrument is not required; or the plant is placed in the protection or safe condition that the instrument initiates. This is accomplished in a normal manner without subjecting the plant to abnormal operating conditions. The action and out-of-service requirements apply to all instrumentation within a particular function, e.g., if the requirements on any one of the ten scram functions cannot be met then control rods shall be inserted.

The trip level settings not specified in Specification 2.3 have been included in this specification. The bases for these settings are discussed below.

The high drywell pressure trip is set at 2.4 psig. This trip will scram the reactor, initiate reactor isolation, initiate containment spray in conjunction with low low reactor water level, initiate core spray, initiate primary containment isolation, initiate automatic depressurization in conjunction with low-low-low-reactor water level, initiate the standby gas treatment system and isolate the reactor building. The scram function shuts the core down during the loss-of-coolant accidents. A steam leak of about 15 gpm and a liquid leak of about 35 gpm from the primary system will cause drywell pressure to reach the scram point; and, therefore the scram provides protection for breaks greater than the above.

High drywell pressure provides a second means of initiating the core spray to mitigate the consequences of a loss-of-coolant accident. Its set point of 2.4 psig initiates the core spray in time to provide adequate core cooling. The break-size coverage of high drywell pressure was discussed above. Low-low water level and high drywell pressure in addition to initiating core spray also causes isolation valve closure. These settings are adequate to cause isolation to minimize the offsite dose within required limits.

It is permissible to make the drywell pressure instrument channels inoperable during performance of the integrated primary containment leakage rate test provided the reactor is in the cold shutdown condition. The reason for this is that the Engineered Safety Features, which are effective in case of a LOCA under these conditions, will still be effective because they will be activated by low-low reactor water level.

The scram discharge volume has two separate instrument volumes utilized to detect water accumulation. The high water level is based on the design that the water in the SDIV's, as detected by either set of level instruments, shall not be allowed to exceed 29.0 gallons; thereby, permitting 137 control rods to scram. To provide further margin, an accumulation of not more than 14.0 gallons of water, as detected by either instrument volume, will result in a rod block and an alarm. The accumulation of not more than 7.0 gallons of water, as detected in either instrument volume will result in an alarm.

Detailed analyses of transients have shown that sufficient protection is provided by other scrams below 45% power to permit bypassing of the turbine trip and generator load rejection scrams. However, for operational convenience, 40% of rated power has been chosen as the setpoint below which these trips are bypassed. This setpoint is coincident with bypass valve capacity.

A low condenser vacuum scram trip of 23" Hg has been provided to protect the main condenser in the event that vacuum is lost. A loss of condenser vacuum would cause the turbine stop valves to close, resulting in a turbine trip

transient. The low condenser vacuum trip anticipates this transient and scrams the reactor. The condenser is capable of receiving bypass steam until 7" Hg vacuum thereby mitigating the transient and providing a margin.

Main steamline high radiation is an indication of excessive fuel failure. Scram and reactor isolation are initated when high activity is detected in the main steam lines. These actions prevent further release of fission products to the environment. This is accomplished by setting the trip at 10 times normal rated power background. Although these actions are initiated at this level, at lower activities the monitoring system also provides for continuous monitoring of radioactivity in the primary steam lines as discussed in Section VII-6 of the FDSAR. Such capability provides the operator with a prompt indication of any release of fission products from the fuel to the reactor coolant above normal rated power background. The gross failure of any single fuel rod could release a sufficient amount of activity to approximately double the background activity at normal rated power. This would be indicative of the onset of fuel failures and would alert the operator to the need for appropriate action, as defined by Section 6 of these specifications.

The settings to isolate the isolation condenser in the event of a break in the steam or condensate lines are based on the predicted maximum flows that these systems would experience during operation, thus permitting operation while affording protection in the event of a break. The settings correspond to a flow rate of less than three times the normal flow rate of 3.2×10^5 lb/hr.

"The setting of ten times the stack release limit for isolation of the air-ejector offgas line is to permit the operator to perform normal, immediate remedial action if the stack limit is exceeded. The time necessary for this action would be extremely short when considering the annual averaging which is allowed under 10 CFR 20.106, and, therefore, would produce insignificant effects on doses to the public."

Four radiation monitors are provided which initiate isolation of the reactor building and operation of the standby gas treatment system. Two monitors are located in the ventilation ducts, one is located in the area of the refueling pool and one is located in the reactor vessel head storage area. The trip logic is basically a 1 out of 4 system. Any upscale trip will cause the desired action. Trip settings of 1 7 mr/hr in the duct and 100 mr/hr on the refueling floor are based upon initiating standby gas treatment system so as not to exceed allowed dose rates of 10 CFR 20 at the nearest site boundary.

The SRM upscale of 5×10^5 CPS initiates a rod block so that the chamber can be relocated to a lower flux area to maintain SRM capability as power is increased to the IRM range. Full scale reading is 1×10^6 CPS. "This rod block is bypassed in IRM Ranges 8 and higher since a level of 5×10^5 CPS is reached and the SRM chamber is at its fully withdrawn position."

The SRM downscale rod block of 100 CPS prevents the instrument chamber from being withdrawn too far from the core during the period that it is required to monitor the neutron flux. "This downscale rod block is also bypassed in IRM Ranges 8 and higher. It is not required at this power level since good indication exists in the Intermediate Range and the SRM will be reading approximately 5×10^5 CPS when using IRM Ranges 8 and higher."

The IRM downscale rod block in conjunction with the chamber full-in position and range switch setting, provides a rod block to assure that the IRM is in its most sensitive condition before startup. If the two latter conditions are satisfied, control rod withdrawal may commence even if the IRM is not reading at least 5%. However, after a substantial neutron flux is obtained, the rod block setting prevents the chamber from being withdrawn to an insensitive area of the core.

The APRM downscale setting of $\geq$ 2/150 full scale is provided in the run mode to prevent control rod withdrawal without adequate neutron monitoring.

High flow in the main steamline is set a 120% of rated flow. At this setting the isolation valves close and in the event of a steam line break limit the loss of inventory so that fuel clad perforation does not occur. The 120% flow would correspond to the thermal power so this would either indicate a line break or too high a power.

Temperature sensors are provided in the steam line tunnel to provide for closure of the main steamline isolation valves should a break or leak occur in this area of the plant. The trip is set at 50°F above ambient temperature at rated power. This setting will cause isolation to occur for main steamline breaks which result in a flow of a few pounds per minute or greater. Isolation occurs soon enough to meet the criterion of no clad perforation.

The low-low-low water level trip point is set at 4'8" above the top of the active fuel and will prevent spurious operation of the automatic relief system. The trip point established will initiate the automatic depressurization system in time to provide adequate core cooling.

Specification 3.1.B.1 defines the minimum number of APRM channel inputs required to permit accurate average core power monitoring. Specifications 3.1.B.2 and 3.1.C.1 further define the distribution of the operable chambers to provide monitoring of local power changes that might be caused by a single rod withdrawal. Any nearby, operable LPRM chamber can provide the required input for average core monitoring. A Travelling Incore Probe or Probes can be used temporarily to provide APRM input(s) until LPRM replacement is possible. Since APRM rod block protection is not required below 61% of rated power,(1) as discussed in Section 2.3, Limiting Safety System Settings, operation may continue below 61% as long as Specification 3.1.B.1 and the requirements of Table 3.1.1 are met. In order to maintain reliability of core monitoring in that quadrant where an APRM is inoperable, it is permitted to remove the operable APRM from service for calibration and/or test provided that the same core protection is maintained by alternate means.

In the rare event that Travelling In-core Probes (TIPs) are used to meet the requirements 3.1.B or 3.1.C, the licensee may perform an analysis of substitute LPRM inputs to the APRM system using spare (non-APRM input) LPRM detectors and change the APRM system as permitted by 10 CFR 50.59.

Under assumed loss-of-coolant accident conditions and under certain loss of offsite power conditions with no assumed loss-of-coolant accident, it is inadvisable to allow the simultaneous starting of emergency core cooling and heavy load auxiliary systems in order to minimize the voltage drop across the emergency buses and to protect against a potential diesel generator overload.

The diesel generator load sequence time delay relays provide this protective function and are set accordingly. The repetitive accuracy rating of the timer mechanism as well as parametric analyses to evaluate the maximum acceptable tolerances for the diesel loading sequence timers were considered in the establishment of the appropriate load sequencing.

Manual actuation can be accomplished by the operator and is considered appropriate only when the automatic load sequencing has been completed. This will prevent simultaneous starting of heavy load auxiliary systems and protect against the potential for diesel generator overload.

Also, the Closed Cooling Water and Service Water pump circuit breakers will trip whenever a loss-of-coolant accident condition exists. This is justified by Amendment 42 of the Licensing Application which determined that these pumps were not required during this accident condition.

Reference:

(1) NEDO-10189 "An Analysis of Functional Common Mode Failures in GE BWR Protection and Control Instrumentation," L. G. Frederick, et al., July 1970.

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
A. Scram								Insert control rods
1. Manual Scram		X	X	X	X	2	1	
2. High Reactor Pressure	**		X(s)	X	X	2	2	
3. High Drywell Pressure	≤ 2.4 psig.		X(u)	X(u)	X	2	2	
4. Low Reactor Water Level	**		X	X	X	2	2	
5. a. High Water Level in Scram Discharge Volume North Side	≤ 29 gal.		X(a)	X(z)	X(z)	2	2	
b. Higher Water Level in Scram Discharge Volume South Side	≤ 29 gal.		X(a)	X(z)	X(z)	2	2	
6. Low Condenser Vacuum	≥ 23" hg.		X(b)	X(b)	X	2	2	
7. High Radiation in Main Steam Line Tunnel	≤ 10 x normal background		X(s)	X	X	2	2	

Amendement No.: 20, 44, 63, 73, 79

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
8. Average Power Range Monitor (APRM)	**		X(c,s)	X(c)	X(c)	2	3	Insert Control rods
9. Intermediate Range Monitor (IRM)	**		X(d)	X(d)		2	3	
10. Main Steamline Isolation Valve Closure	**		X(b,s)	X(b)	X	2	4	
11. Turbine Trip Scram	**				X(j)	2	4	
12. Generator Load Rejection Scram	**				X(j)	2	2	
B. Reactor Isolation								Close main steam isolation valves and close isolation condenser vent valves, or place in cold shutdown condition
1. Low-Low Reactor Water Level	**	X	X	X	X	2	2	
2. High Flow in Main Steamline A	≤ 120% rated	X(s)	X(s)	X	X	2	2	
3. High Flow in Main Steamline B	≤ 120% rated	X(s)	X(s)	X	X	2	2	

Change: 8
Amendemnt No.: 44

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
4. High Temperature in Main Steamline Tunnel	≤ Ambient at Power + 50°F	X(s)	X(s)	X	X	2	2	
5. Low Pressure in Main Steamline	**			X(cc)	X	2	2	
6. High Radiation in Main Steam Tunnel	≤ 10X Normal Background	X(s)	X(s)	X	X	2	2	
C. Isolation Condenser								
1. High Reactor Pressure	**	X(s)	X(s)	X	X	2	2	Place plant in cold shutdown condition
2. Low-Low Reactor Water	≥ 7'22" above top of active fuel	X(s)	X(s)	X	X	2	2	

Correction: 8
Amendment No.: 9, 44, 71

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
D. Core Spray								Consider the respective core spray loop inoperable, and comply with Spec. 3.4
1. Low-Low Reactor Water Level	**	X(t)	X(t)	X(t)	X	2	2	
2. High Drywell Pressure	≤ 2.4 psig	X(t)	X(t)	X(t)	X	2(k)	2(k)	
3. Low Reactor Pressure (valve permissive)	≥ 285 psig	X(t)	X(t)	X(t)	X	2	2	
E. Containment Spray								Consider the containment spray loop inoperable and comply with Spec. 3.4
1. High Drywell Pressure	≤ 2.4 psig	X(u)	X(u)	X(u)	X	2(k)	2(k)	
2. Low-Low Reactor Water Level	≥ 7'2" above top of active fuel	X(u)	X(u)	X(u)	X	2	2	
F. Primary Containment Isolation								Isolate containment or place in cold shutdown condition
1. High Drywell Pressure	≤ 2.4 psig	X(u)	X(u)	X(u)	X	2(k)	2(k)	
2. Low-Low Reactor Water Level	≥ 7'2" above top of active fuel	X(u)	X(u)	X(u)	X	2	2	

Change: 4
Amendment No.: 44 , 79

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
G. Automatic Depressurization								
1. High Drywell Pressure	≤ 2.4 psig	X(v)	X(v)	X(v)	X	2(k)	2(k)	See note h
2. Low-Low-Low Reactor Water Level	≥ 4'8" above top of active fuel	X(v)	X(v)	X(v)	X	2	2	See note h
3. AC Voltage	NA			X(v)	X	2	2	Prevent auto depressurization on loss of AC power. See note i
H. Isolation Condenser Isolation								
1. High Flow Steam Line	≤ 20 psig P	X(s)	X(s)	X	X	2	2	Isolate Affected Isolation condensor, comply with Spec. 3.8 See note dd
2. High Flow Condensate Line	≤ 27" P H_2O	X(s)	X(s)	X	X	2	2	
I. Offgas System Isolation								
1. High Radiation In Offgas Line (e)	≤ 10 x Stack Release limit (See 3.6-A.1)	X(s)	X(s)	X	X	1	2	Isolate reactor or trip the Inoperable in-instrument channel

Change: 4
Amendment No.: 72, 79
Correction: 5/11/84

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
J. Reactor Building Isolation and Standby Gas Treatment System Initiation								Isolate Reactor Bldg. and Initiate Standby Gas Treatment System or Manual Surveillance for not more than 24 hours (total for all instruments under J) in any 30-day period
1. High Radiation Reactor Building Operation Floor	≤ 100 Mr/Hr	X(w)	X(w)		X	1	1	
2. Reactor Bldg. Ventilation Exhaust	≤ 100 Mr/Hr	X(w)		X		1	1	
3. High Drywell Pressure	≤ 2.4 psig	X(u)	X(u)	X	X	1(k)	2(k)	
4. Low Low Reactor Water Level	≥ 7'2" above top of active fuel	X(gg)	X	X	X	1	2	
K. Rod Block								No control rod withdrawals permitted
1. SRM Upscale	≤ 5×10^5 cps		X	X(1)		1	2	
2. SRM Downscale	≥ 100 cps(f)		X	X(1)		1	2	
3. IRM Downscale	≥ 5/125 fullscale(g)		X	X		2	3	
4. APRM Upscale	**		X(s)	X	X	2	3(c)	
5. APRM Downscale	≥ 2/150 fullscale				X	2	3(c)	

Corrected: 12/24/84
Amendment No.: 15, 44, 63, 73, 75, 79, 91

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
6. IRM Upscale	≤ 108/125 fullscale		X	X		2	3	
7. a) water level high scram discharge volume North	≤ 14 gallons		X(z)	X(z)	X(z)	1	1 per instrum. volume	
b) water level high scram discharge volume South	≤ 14 gallons		X(z)	X(z)	X(z)	1	1 per instrum. volume	
L. Condenser Vacuum Pump Isolation								Insert Control Rods
1. High Radiation in Main Steam Tunnel	≤ 10 x Normal background		During Startup and Run when vacuum pump 1 operating			2	2	
M. Diesel Generator Load Sequence Timers	Time delay after energization of relay							Consider containment spray loop inoperable and comply with Spec. 3.4.C (See note q.).
1. Containment Spray Pump	40 sec ± 15%	X	X	X	X	2(m)	1(n)	
2. CRD pump	60 sec ± 15%	X	X	X	X	2(m)	1(n)	Consider the pump inoperable and comply

Amendment No.: 15, 44, 60, 63

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS (CONTD)

Function	Trip Setting	Reactor Modes in which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Min. No. of Operable or Operating [tripped] Trip Systems	Min. No. of Instrument Channels Per Operable Trip Systems	Action Required*
								with Spec. 3.4.D (See Note q)
3. Emerg. Service Water Pump (r)	45 sec ± 15%	X	X	X	X	2(m)	1(n)	Consider the loop inoperable and comply with Spec. 3.4.C (See Note q)
4. Service Water Pump (aa)	120 sec. ± 15% (SK1A) 10 sec. + 15% (SK2A) (SK7A) (SK8A)	X	X	X	X	2(o)	2(p)	Consider the pump inoperable and comply within 7 days (See note q)
5. Closed Cooling Water Pump (bb)	166 Sec. ± 15%	X	X	X	X	2(m)	1(n)	Consider the pump inoperable and comply within 7 days (See Note q)
N. Loss of Power								
a. 4.16KV Emergency Bus Undervoltage (Loss of Voltage)	**	X(ff)	X(ff)	X(ff)	X(ff)	2	1	
b. 4.16 KV Emergency Bus undervoltage (Degraded Voltage)	**	X(ff)	X(ff)	X(ff)	X(ff)	2	3	See Note ee

TABLE 3.1.1 (CONTD)

* Action required when minimum conditions for operation are not satisfied. Also permissible to trip inoperable trip system. When necessary to conduct tests and calibrations, one channel may be made inoperable for up to one hour per month without tripping its trip system.

** See Specification 2.3 for Limiting Safety System Settings.

Notes:

a. Permissible to bypass, with control rod block, for reactor protection system reset in refuel mode.
b. Permissible to bypass below 800 psia in refuel and startup modes.
c. One (1) APRM in each operable trip system may be bypassed or inoperable provided the requirements of specification 3.1.C and 3.10.C are satisfied. Two APRM's in the same quadrant shall not be concurrently bypassed except as noted below or permitted by note.

Any one APRM may be removed from service for up to one hour for test or calibration without inserting trips in its trip system only if the remaining operable APRM's meet the requirements of specification 3.1.B.1 and no control rods are moved outward during the calibration or test. During this short period, the requirements of specifications 3.1.B.2, 3.1.C and 3.10.C need not be met.

d. The IRM shall be inserted and operable until the APRM's are operable and reading at least 2/150 full scale.
e. Air ejector isolation valve closure time delay shall not exceed 15 minutes.
f. Unless SRM chambers are fully inserted.
g. Not applicable when IRM on lowest range.
h. One instrument channel in each trip system may be inoperable provided the circuit which it operates in the trip system is placed in a simulated tripped condition. If repairs cannot be completed within 72 hours the reactor shall be placed in the cold shudown condition. If more than one instrument channel in any trip system becomes inoperable, the reactor shall be placed in the cold shutdown condition. Relief valve controllers shall not be bypassed for more than 3 hours (total time for all controllers) in any 30-day period and only one relief valve controller may be bypassed at a time.
i. The interlock is not required during the start-up test program and demonstration of plant electrical output but shall be provided following these actions.
j. Not required below 40% of turbine rated steam flow.
k. All four (4) drywell pressure instrument channels may be made inoperable during the integrated primary containment leakage rate test (See Specification 4.5), provided that the plant is in the cold shutdown condition and that no work is performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the top of the active fuel.
l. Bypass in IRM Ranges 8, 9, and 10.

TABLE 3.1.1 (CONTD)

m. There is one time delay relay associated with each of two pumps.
n. One time delay relay per pump must be operable.
o. There are two time delay relays associated with each of two pumps. One timer per pump is for sequence starting (SK1A, SK2A) and one timer per pump is for tripping the pump circuit breaker (SK7A, SK8A).
p. Two time delay relays per pump must be operable.
q. Manual initiation of affected component can be accomplished after the automatic load sequencing is completed.
r. Time delay starts after closing of containment spray pump circuit breaker.
s. These functions not required to be oprable with the reactor temperature less than 212°F and the vessel head removed or vented.
t. These functions may be operable or bypassed when corresponding portions in the same core spray system logic train are inoperable per Specification 3.4.A.
u. These functions not required to be operable when primary containment integrity is not required to be maintained.
v. These functions not required to be operable when the ADS is not required to be operable.
w. These functions must be operable only when irradiated fuel is in the fuel pool or reactor vessel and secondary containment integrity is required per specification 3.5.B.
y. The number of operable channels may be reduced to 2 per Specification 3.9-E and F.
z. The bypass function to permit scram reset in the shutdown or refuel mode with control rod block must be operable in this mode.
aa. Pump circuit breakers will be tripped in 10 seconds ± 15% during a LOCA by relays SK7A and SK8A.
bb. Pump circuit breakers will trip instantaneously during a LOCA.
cc. Only applicable during startup mode while operating in IRM range 10.
dd. If an isolation condenser inlet (steam side) isolation valve becomes or is made inoperable in the open position during the run mode comply with Specification 3.8.E. If an AC motor-operated outlet (condensate return) isolation valve becomes or is made inoperable in the open position during the run mode comply with Specification 3.8.F.
ee. With the number of operable channels one less than the Min. No. of Operable Instrument Channels per Operable Trip Systems, operation may proceed until performance of the next required Channel Functional Test provided the inoperable channel is placed in the tripped condition within 1 hour.
ff. This function is not required to be operable when the associated safety bus is not required to be energized or fully operable as per applicable sections of these technical specifications.
*gg. These functions are not required to be operable when secondary containment is not required to be maintained or when the conditions of Sections 3.5.b.1.a, b, c, and d are met, and reactor water level is closely monitored and logged hourly. The Standby Gas Treatment System will be manually initiated if reactor water level drops to the low level trip set point.
* this note is applicable only during the Cycle 10M outage.

3.2 REACTIVITY CONTROL

Applicability: Applies to core reactivity and the operating status of the reactivity control systems for the reactor.

Objective: To assure reactivity control capability of the reactor.

Specification:

A. Core Reactivity

The core reactivity shall be limited such that the core could be made subcritical at any time during the operating cycle, with the strongest operable control rod fully withdrawn and all other operable rods fully inserted.

B. Control Rod System

1. The control rod drive housing support shall be in place during power operation and 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 3.2.A is met.

2. The Rod Worth Minimizer (RWM) shall be operable during each reactor startup until reactor power reaches 10% of rated power except as follows:

   (a) Should the RWM become inoperable after the first twelve rods have been withdrawn, the startup may continue provided that a second licensed operator verifies that the licensed operator at the reactor console is following the rod program.

   (b) Should the RWM be inoperable before a startup is commenced or before the first twelve rods are withdrawn, one startup during each calendar year may be performed without the RWM provided that the second licensed operator verifies that the licensed operator at the reactor console is following the rod program and provided that a reactor engineer from the Core Engineering Group also verifies that the rod program is being followed. A startup without the RWM as described in this subsection shall be reported in a special report to the Nuclear Regulatory Commission (NRC) within 30 days of the startup stating the reason for the failure of the RWM, the action taken to repair it and the schedule for completion of the repairs.

   Control rod withdrawal sequences shall be established with a banked position withdrawal sequence so that the rod drop accident design limit of 280 cal/gm is not exceeded. For control rod withdrawal sequences not in strict compliance to BPWS, the maximum in sequence rod worth shall be $\leq$1.0% ΔK.

3. The average of the scram insertion times of all operable control rods shall be no greater than:

Rod Length Inserted (Percent)	Insertion Time (Seconds)
5	0.375
20	0.900
50	2.00
90	5.00

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

Rod Length Inserted (Percent)	Insertion Time (Seconds)
5	0.398
20	0.954
50	2.120
90	5.300

Any four rod group may contain a control rod which is valved out of service provided the above requirements and Specification 3.2.A are met. Time zero shall be taken as the de-energization of the pilot scram valve solenoids.

4. Control rods 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 a shutdown condition within 48 hours unless investigation demonstrates that the cause of the failure is not due to a failed control rod drive mechanism collet housing. Inoperable control rods shall be valved out of service, in such positions that Specification 3.2.A is met. In no case shall the number of rods valved out of service be greater than six during the power operation. If this specification is not met, the reactor shall be placed in the shutdown condition.

5. Control Rods shall not be withdrawn for approach to criticality unless at least two source range channels have an observed count rate equal to or greater than 3 counts per second.

C. Standby Liquid Control System

1. The standby liquid control system shall be operable at all times when the reactor is not shut down by the control rods such that Specification 3.2.A is met and except as provided in Specification 3.2.C.3.

2. The standby liquid control solution shall be maintained within the volume-concentration requirement area in Figure 3.2-1 and at a temperature not less than the temperature presented in Figure 3.2-2 at all times when the standby liquid control system is required to be operable.

3. If one standby liquid control system pumping circuit becomes inoperable during the RUN mode and Specification 3.2.A is met, the reactor may remain in operation for a period not to exceed 7 days, provided the pump in the other circuit is demonstrated daily to be operable.

D. Reactivity Anomalies

The difference between an observed and predicted control rod inventory shall not exceed the equivalent of one percent in reactivity. If this limit is exceeded and the discrepancy cannot be explained, the reactor shall be brought to the cold shutdown condition by normal orderly shutdown procedure. Operation shall not be permitted until the cause has been evaluated and appropriate corrective action has been completed. The NRC shall be notified within 24 hours of this situation in accordance with Specification 6.6.

Bases:

Limiting conditions of operation on core reactivity and the reactivity control systems are required to assure that the excess reactivity of the reactor core is controlled at all times. The conditions specified herein assure the capability to provide reactor shutdown from steady state and transient conditions and assure the capability of limiting reactivity insertion rates under accident conditions to values which do not jeopardize the reactor coolant system integrity or operability of required safety features.

The core reactivity limitation is required to assure the reactor can be shut down at any time when fuel is in the core. It is a restriction that must be incorporated into the design of the core fuel; it must be applied to the conditions resulting from core alterations; and it must be applied in determining the required operability of the core reactivity control devices. The basic criterion is that the core at any point in its operation be capable of being made subcritical in the cold, xenon-free condition with the operable control rod of highest worth fully withdrawn and all other operable rods fully inserted. At most times in core life more than one control rod drive could fail mechanically and this criterion would still be met.

In order to assure that the basic criterion will be satisfied an additional design margin was adopted; that the k_{eff} be less than 0.99 in the cold xenon-free condition with the rod of highest worth fully withdrawn and all others fully inserted. Thus the design requirement is $k_{eff} < 0.99$, whereas the minimum condition for operation is $k_{eff} < 1.0$ with the operable rod of highest worth fully withdrawn (1). This limit allows control rod testing at any time in core life and assures that the plant can be shut down by control rods alone.

Fuel bundles containing gadolinia as a burnable neutron absorber results in a core reactivity characteristic which increases with exposure, goes through a maximum and then decreases. Thus it is possible that a core could be more reactive later in the cycle than at the beginning. Satisfaction of the above criterion can be demonstrated conveniently only at the time of refueling since it requires the core to be cold and xenon-free. The demonstration is designed to be done at these times and is such that if it is successful, the criterion is satisfied for the entire subsequent fuel cycle. The criterion will be satisfied by demonstrating Specification 4.2.A at the beginning of each fuel cycle with the core in the cold, xenon-free condition. This demonstration will include consideration for the calculated reactivity characteristic during the following operating cycle and the uncertainty in this calculation.

The control rod drive housing support restricts the outward movement of a control rod to less than 3 inches in the extremely remote event of a housing failure (2). 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 reactor coolant system. The support is not required when no fuel is in the core since no nuclear consequences could occur in the absence of fuel. The 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. The support is not required if all control rods are fully inserted since the reactor would remain subcritical even in the event of complete ejection of the strongest control rod (3).

The Rod Worth Minimizer (4) provides automatic supervision of conformance to the specified control rod patterns. It serves as a back-up to procedural control of control rod worth. In the event that the RWM is out of service when required, a licensed operator can manually fulfill the control rod pattern conformance functions of the RWM in which case the normal procedural controls are backed up by independent procedural controls to assure conformance during control rod withdrawal. This allowance to perform a startup without the RWM is limited to once each calendar year to assure a high operability of the RWM which is preferred over procedural controls.

Control rod drop accident (RDA) results for plants using banked position withdrawal sequences (BPWS) show that in all cases the peak fuel enthalpy in an RDA would be much less than the 280 cal/gm design limit even with the maximum incremental rod worth. The BPWS is developed prior to initial operation of the unit following any refueling outage and the requirement that the operator follow the BPWS is supervised by the RWM or a second licensed operator. If it is necessary to deviate slightly from the BPWS sequence (i.e. due to an inoperable control rod) no further analysis is needed if the maximum incremental rod worth in the modified sequence is $\leq$1.0% ΔK. An incremental control rod worth of $\leq$1.0% ΔK will not result in a peak fuel enthalpy above the design limit of 280 cal/gm as documented in reference 10.

The BPWS limits the reactivity worths of control rods and together with the integral rod velocity limiters and the action of the control rod drive system limits potential reactivity insertion such that the results of a control rod

drop accident will not exceed a maximum fuel energy content of 280 cal/gm. Method and basis for the rod drop accident analyses are documented in Reference 5.

The control rod system is designed to bring the reactor subcritical from a scram signal at a rate fast enough to prevent fuel damage. Scram reactivity curve for the transient analyses is calculated and evaluated with each reload core. In the analytical treatment of the transients, 290 milliseconds are allowed between a neutron sensor reaching the scram point and the start of motion of the control rods. This is adequate and conservative when compared to the typical time delay of about 210 milliseconds estimated from scram test results. Approximately the first 90 milliseconds of each of these time intervals result from the sensor and circuit delays when the pilot scram solenoid de-energizes. Approximately 120 milliseconds later, the control rod motion is estimated to actually begin. However, 200 milliseconds is conservatively assumed for this time interval in the transient analyses and this is also included in the allowable scram insertion times of Specification 3.2.B.3. The specified limits provide sufficient scram capability to accommodate failure to scram of any one operable rod. This failure is in addition to any inoperable rods that exist in the core, provided that those inoperable rods met the core reactivity Specification 3.2.A.

Control rods (6) which cannot be moved with control rod drive pressure are clearly indicative of an abnormal operating condition on the affected rods and are, therefore, considered to be inoperable. Inoperable rods are valved out of service to fix their position in the core and assure predictable behavior. If the rod is fully inserted and then valved out of service, it is in a safe position of maximum contribution to shutdown reactivity. If it is valved out of service in a non-fully inserted position, that position is required to be consistent with the shutdown reactivity limitation stated in Specification 3.2.A, which assures the core can be shut down at all times with control rods. Before rod is valved out of service in a non-fully inserted position an analysis is performed to insure Specification 3.2.A is met.

The number of rods permitted to be valved out of service could be many more than the six allowed by the specification, particularly late in the operating cycle; however, the occurrence of more than six could be indicative of a generic problem and the reactor will be shut down. 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 collet housing and requiring increased surveillance after detecting one stuck rod will assure that the reactor will not be operated with a large number of rods with failed collet housings. Placing the reactor in the shutdown condition inserts the control rods and accomplishes the objective of the specifications on control rod operability. This operation is normally expected to be accomplished within eight hours.

The source range monitor (SRM) system (7) performs no automatic safety function. It does provide the operator with a visual indication of neutron level which is needed for knowledgeable and efficient reactor startup at low neutron levels. The results of the reactivity accidents are functions of the initial neutron flux. The requirement of at least 3 cps assures that any transient begins at or above the initial value of 10^{-8} of rated power used in the analyses of transients from cold conditions. One operable SRM channel would be adequate to monitor the approach to critical using homogeneous patterns of scattered control rods.

The standby liquid control system is designed to bring the reactor to a cold shutdown condition from the full power steady state operating condition at any time in core life independent of the control rod system capabilities (8). If the reactor is shutdown by the control rod system and would be subcritical in its most reactive condition as required in Specification 3.2.A, there is no requirement for operability of this system. To bring the reactor from full power to cold shutdown, sufficient liquid control must be inserted to give a negative reactivity worth equal to the combined effects of rated coolant voids, fuel Doppler, xenon, samarium, and temperature change plus shutdown margin. This requires a boron concentration of 600 ppm in the reactor. An additional 25% boron, which results in an average boron concentration in the reactor of 750 ppm, is inserted to provide margin for mixing uncertainties in the reactor. The system is required to insert the solution in a time interval between 60-120 minutes to provide for good mixing in the reactor and to override the rate of reactivity insertion due to cooldown of the reactor following the xenon peak.

The liquid control tank volume-concentration requirements of Figure 3.2-1 assure that the above requirements for liquid control insertion are met with one 30 gpm liquid control pump. The point (1937 gal, 19.6% solution) (9) results in the required amount of solution being inserted into the reactor in not less than 60 minutes, and therefore, defines the maximum concentration-minimum volume requirement. The point (3737 gal, 10.3% solution) (9) results in the required amount of solution being injected into the reactor in not more than 120 minutes, and therefore, defines the minimum concentration requirement. The boundary joining these points results in the required amount of solution being inserted into the reactor in the interval 60-120 minutes. The maximum volume of 4213 gal is established by the tank capacity. The tank volume requirements include consideration for 137 gal of solution which is contained below the point where the pump takes suction from the tank and, therefore, cannot be inserted into the reactor. The range of solution volume during normal operation is expected to be 2387-2937 gal.

The solution saturation temperature varies with the concentration of sodium pentaborate. The solution will be maintained at least 5°F above the saturation temperature to guard against precipitation. The 5°F margin is included in Figure 3.2-1. Temperature and liquid level alarms for the system are annunciated in the control room.

The acceptable time out of service for a standby liquid control system pumping circuit as well as other safety features is determined to be

10 days. However, the allowed time out of service for a standby liquid control system pumping circuit is conservatively set at 7 days in the specification. Systems are designed with redundancy to increase their availability and to provide backup if one of the components is temporarily out of service.

During each fuel cycle excess operating reactivity varies as fuel depletes and as any burnable poison in supplementary control is burned. The magnitude of this excess reactivity is indicated by the integrated worth of control rods inserted into the core, referred to as the control rod inventory in the core. As fuel burnup progresses, anomalous behavior in the excess reactivity may be detected by comparison of actual rod inventory with expected inventory based on appropriately corrected past data. Experience at Oyster Creek and other operating BWR's indicates that the control rod inventory should be predictable to the equivalent of one percent in reactivity. Deviations beyond this magnitude would not be expected and would require thorough evaluation. One percent reactivity limit is considered safe since an insertion of this reactivity into the core would not lead to transients exceeding design conditions of the reactor system.

References:

(1) FDSAR, Volume I, Section III-5.3.1
(2) FDSAR, Volume I, Section VI-3
(3) FDSAR, Volume I, Section III-5.2.1
(4) FDSAR, Volume I, Section VII-9
(5) NEDO-24195, General Electric Reload Fuel Application for Oyster Creek
(6) FDSAR, Volume I, Section III-5 and Volume II, Appendix B
(7) FDSAR, Volume I, Sections VII-4.2.2 and VII-4.3.1
(8) FDSAR, Volume I, Section VI-4
(9) FDSAR, Amendment No. 55, Section 2
(10) C. J. Paone, Banked Position Withdrawal Sequence, January 1977 (NEDO-21231)

3.3 REACTOR COOLANT

Applicability: Applies to the operating status of the reactor coolant system.

Objective: To assure the structure integrity of the reactor coolant system.

Specification: A. Pressure Temperature Relationships

(i) Hydrostatic Leakage Tests - the minimum reactor vessel temperature for hydrostatic leakage tests at a given pressure shall be in excess of that indicated by Curve A of Figure 3.3.1.

(ii) Heatup and Cooldown Operations: Reactor noncritical--the minimum reactor vessel temperature for heatup and cooldown operations at a given pressure when the reactor is not critical shall be in excess of that indicated by Curve B of Figure 3.3.1.

(iii) Power operations--The minimum reactor vessel temperature for power operations at a given pressure shall be in excess of that indicated by Curve C of Figure 3.3.1.

(iv) Appropriate new pressure temperature limits must be approved as part of this Technical Specification when the reactor system has reached ten effective full power years of reactor operation.

B. Reactor Vessel Closure Head Boltdown

The reactor vessel closure head studs may be elongated by .020" (1/3 design preload) with no restrictions on reactor vessel temperature as long as the reactor vessel is at atmospheric pressure. Full tensioning of the studs is not permitted unless the temperature of the reactor vessel flange and closure head flange is in excess of 100°F.

C. Thermal Transients

1. The average rate of reactor coolant temperature change during normal heatup and cooldown shall not exceed 100°F in any one hour period.

2. The pump in an idle recirculation loop shall not be started unless the temperature of the coolant within the idle recirculation loop is within 50°F of the reactor coolant temperature.

D. Reactor Coolant System Leakage

1. Reactor coolant system leakage shall be limited to:

   a. 5 gpm unidentified leakage
   b. 25 gpm total (identified and unidentified)
   c. 2 gpm increase in unidentified leakage rate within any 4 hour period while operating at steady state power

2. With the reactor coolant system leakage greater than the limits in 3.3.D.1.a or b above, reduce the leakage rate to within the acceptable limits within 8 hours, or place the reactor in the shutdown condition within the next 12 hours and be in the cold shutdown condition within the following 24 hours.

3. With any reactor coolant leakage greater than the limit in 3.3.D.1.c above, identify the source of leakage within 4 hours, or be in the shutdown condition within the next 12 hours and be in the cold shutdown condition within the following 24 hours.

4. For determination of unidentified leakage, the primary containment sump flow monitoring system shall be operable except as specified below:

   a. With the primary containment sump flow integrator inoperable:

      1. Restore it to operable status within 7 days.
      2. Calculate the unidentified leakge rate utilizing an acceptable alternate means as specified in plant procedures.

   b. If Specification 3.3.D.4.a cannot be met, place the reactor in the shutdown condition within the next 12 hours.

5. For determination of identified leakage, the primary containment equipment drain tank monitoring system shall be operable except as specified below:

   a. With the primary containment equipment drain tank monitoring system inoperable:

      1. Restore it to operable status within 7 days.
      2. Calculate the identified leakage rate utilizing an acceptable alternate means as specified in plant procedures.

   b. If Specification 3.3.D.5.a cannot be met, place the reactor in the shutdown condition within the next 12 hours.

E. Reactor Coolant Quality

1. The reactor coolant quality during power operation with steaming rates to the turbine-condenser of less than 100,000 pounds per hour shall be limited to:

conductivity	2 uS/cm	(S = mhos at 25°C(77°F))
chloride ion	0.1 ppm	

2. When the conductivity and chloride concentration limits given in 3.3.E.1 are exceeded, an orderly shutdown shall be initiated immediately, and the reactor coolant temperature shall be reduced to less than 212°F within 24 hours.

3. The reactor coolant quality during power operation with steaming rates to the turbine-condenser of greater than or equal to 100,000 pounds per hour shall be limited to:

conductivity	10 uS/cm	(S = mhos at 25°C(77°F))
chloride ion	0.5 ppm	

4. When the maximum conductivity or chloride concentration limits given in 3.3.E.3 are exceeded, an orderly shutdown shall be initiated immediately, and the reactor coolant temperature shall be reduced to less than 212°F within 24 hours.

5. During power operation with steaming rates on the turbine-condenser of greater than or equal to 100,000 pounds per hour, the time limit above 1.0 uS/cm at 25°C (77°F) and 0.2 ppm chloride shall not exceed 72 hours for any single incident.

6. When the time limits for 3.3.E.5 are exceeded, an orderly shutdown shall be initiated within 4 hours.

F. Recirculation Loop Operability

1. The reactor shall not be operated with one or more recirculation loops out of service except as specified in Specification 3.3.F.2.

2. Reactor Operation with one idle recirculation loop is permitted provided that the idle loop is not isolated from the reactor vessel.

3. If Specifications 3.3.F.1 and 3.3.F.2 are not met, the reactor shall be placed in the cold shutdown condition within 24 hours.

G. Primary Coolant System Pressure Isolation Valves

Applicability:

Operational conditions - Startup and Run Modes; applies to the operational status of the primary coolant system pressure isolation valves.

Objective:

To increase the reliability of primary coolant system pressure isolation valves thereby reducing the potential of an inter-system loss of coolant accident.

Specification:

1. During reactor power operating conditions, the integrity of all pressure isolation valves listed in Table 3.3.1 shall be demonstrated. Valve leakage shall not exceed the amounts indicated.

2. If Specification 1 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

H. Required Minimum Recirculation Flow Rate for Operation in RM Range 10

1. During STARTUP mode operation, a minimum recirculation flow rate is required before operating in IRM range 10 to ensure that technical specification transient MCPR limits for operation are not exceeded. This minimum flow rate is no longer required once the reactor is in the RUN mode.

2. 39.65×10^6 lb/hr is the minimum recirculation flow rate necessary for operation in IRM range 10 at this time. This flow rate leaves sufficient margin between the minimum flow required by the RWE analysis performed and the minimum flow used while operating in IRM range 10.

NRC Order Dated April 20, 1981

Bases: The reactor coolant system(1) is a primary barrier against the release of fission products to the environs. In order to provide assurance that this barrier is maintained at a high degree of integrity, restrictions have been placed on the operating conditions to which it can be subjected.

The Oyster Creek reactor vessel was designed and manufactured in accordance with General Electric Specification 21A1105 and ASME Section I as discussed in Reference 13. The original operating limitations were based upon the requirement that the minimum temperature for pressurization be at least 60°F greater than the nil ductility

transformation temperature. The minimum temperature for pressurization at any time in life had to account for the toughness properties in the most limiting regions of the reactor vessel, as well as the effects of fast neutron embrittlement.

Figures 3.3.1 is derived from an evaluation of the fracture toughness properties performed for Oyster Creek (Reference 12) in an effort to establish new operating limits. The results of neutron flux dosimeter analyses in Reference 12 indicate that the total fast neutron fluence (>1 Mev) expected for Oyster Creek at the end of ten effective full power years of operation is 1.22×10^{18} nvt on the inside surface of the reactor vessel core region shell. A conservative fast neutron fluence of 75% of this value is assumed at the 1/4 T (one quarter of wall thickness) location for the preparation of the pressure/temperature curves in Figure 3.3.1.

Stud tensioning is considered significant from the standpoint of brittle fracture only when the preload exceed approximately 1/3 of the final design value. No vessel or closure stud minimum temperature requirements are considered necessary for preload values below 1/3 of the design preload with the vessel depressurized since preloads below 1/3 of the design preload result in vessel closure and average bolt stresses which are less than 20% of the yield strengths of the vessel and bolting materials. Extensive service experience with these materials has confirmed that the probability of brittle fracture is extremely remote at these low stress levels, irrespective of the metal temperature.

The reactor vessel head flange and the vessel flange in combination with the double "O" ring type seal are designed to provide a leak tight seal when bolted together. When the vessel head is placed on the reactor vessel, only that portion of the head flange near the inside of the vessel rests on the vessel flange. As the head bolts are replaced and tensioned, the vessel head is flexed slightly to bring together the entire contact surfaces adjacent to the "O" rings of the head and vessel flange. Both the head and the head flange have an NDT temperature of 40°F, and they are not subject to any appreciable neutron radiation exposure. Therefore, the minimum vessel head and head flange temperature for bolting the head flange and vessel flange is established as 40°F + 60°F or 100°F.

Detailed stress analyses(4) were made on the reactor vessel for both steady state and transient conditions with respect to material fatigue. The results of these analyses are presented and compared to allowable stress limits in Reference (4). The specific conditions analyzed included 120 cycles of normal startup and shutdown with a heating and cooling rate of 100°F per hour applied continuously over a temperature range of 100°F to 546°F and for 10 cycles of emergency cooldown at a rate of 300°F per hour applied over the same range. Thermal stresses from this analysis combined with the primary load stresses fall within ASME Code Section III allowable stress intensities. Although the Oyster Creek Unit 1 reactor vessel was built in accordance with Section I of the ASME Code, the design criteria included in the reactor vessel specifications were in essential agreement with the criteria subsequently incorporated into Section III of the Code.(6)

The expected number of normal heatup and cooldown cycles to which the vessel will be subjected is 80(7). Although no heatup or cooldown rates of 300°F per hour are expected over the life of the vessel and the vessel design did not consider such events(6), stress analyses have been made which showed the allowable number of such events is 22,000 on the basis of ASME Section III alternating stress limits.

During reactor operation, the temperature of the coolant in an idle recirculation loop is expected to remain at reactor coolant temperature unless it is valved out of service. Requiring the coolant temperature in an idle loop to be within 50°F of the reactor coolant temperature before the pump is started assures that the change in coolant temperature at the reactor vessel nozzles and bottom head region are within the conditions analyzed for the reactor vessel as discussed above.

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 AC 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(8) 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 the 3.3-D 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 3.3-D, 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 of the magnitude specified can be detected reasonably in a matter of a few hours utilizing the available leakage detection schemes, and if the origin cannot be determined in a reasonably short time the plant should be shut down to allow further investigation and corrective action.

The drywell floor drain sump and equipment drain tank provide the primary means of leak detection(9,10). Identified leakage is that from valves and pumps in the reactor system and from the reactor vessel head flange gasket. Leakage through the seals of this equipment is piped to the drywell equipment drain tank. Leakage from other sources is classified as unidentified leakage and is collected in the drywell floor drain sump. Leakage which does not flash in a vapor will drain in the sump. The vapor will be condensed in the drywell ventilation system and routed to the sump.

Condensate cannot leave the sump or the drywell equipment drain tank unless the respective pumps are running. The sump and the drain tank are provided with two pumps each. Alarms are provided for the sump that will actuate on a predetermined pumpout rate(10) and will be set to actuate at a leakage that is less than the unidentified leakage limit of 5 gpm.

Additional qualitative information(10) is available to the operator via the monitored drywell atomospheric condition. However, this information is not quantitative since fluctuation in atmospheric conditions are normally expected, and quantitative measurements are not possible. The temperature of the closed cooling water which serves as coolant for the drywell ventilation system is monitored and also provides information which can be related to reactor coolant system leakage(9). Additional protection is provided by the drywell high pressure scram which would be expected to be reached within 30 minutes of a steam leak of about 12 gpm(10).

During a loss of offsite AC power, the control rod drive hydraulic pumps, which are powered by the diesels, each can supply 110 gpm water makeup to the reactor vessel. A 25 gpm limit for total leakage, identified and unidentified, was established to be less than the 110 gpm makeup of a single rod drive hydraulic pump to avoid the use of the emergency core cooling system in the event of a loss of normal AC power.

Materials in the primary system are primarily 304 stainless steel and zircaloy fuel cladding. The reactor water chemistry limits are placed upon conductivity and chloride concentration since conductivity is measured continuously and gives an indication of abnormal conditions or the presence of unusual materials in the coolant, while chloride limits are specified to prevent stress corrosion cracking of stainless steel.

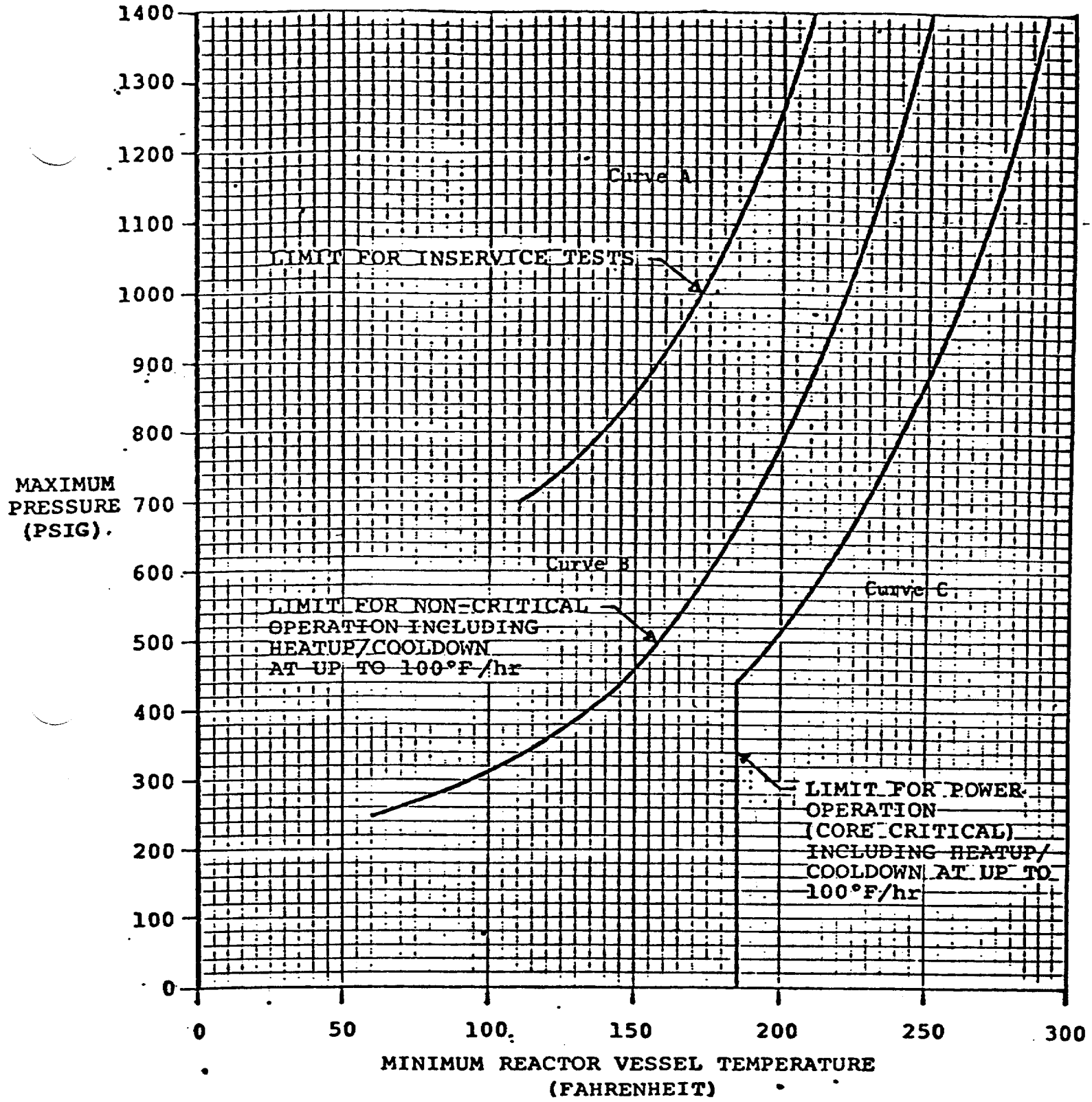
Chlorides are known to (1) promote intergranular stress corrosion cracking of sensitized stainless steels, (2) induce transgranular cracking of non-sensitized stainless steels, (3) promote pitting and (4) promote crevice attack in most RCS materials (BWR Water Chemistry Guidelines, EPRI, April 1, 1984). The higher the concentration, the faster the attack. Therefore, the level of chloride in the reactor water should be kept as low as is practically achievable. The limits are therefore set to be consistent with Regulatory Guide 1.56 (Rev. 1.)

In the case of BWR's where no additives are used in the primary coolant, and where neutral pH is maintained, conductivity provides a very good measure of the quality of the reactor water. When the conductivity is within its proper normal range, pH, chloride, and other impurities affecting conductivity and water quality must also be within their normal ranges. Significant changes in conductivity provide the operator with a warning mechanism so that he can investigate and remedy the conditions causing the change. Measurements of

pH, chloride, and other chemical parameters are made to determine the cause of the unusual conductivity and instigate proper corrective action. These can be done before limiting conditions, with respect to variables affecting the boundaries of the reactor coolant, are exceeded. Several techniques are available to correct off-standard reactor water quality conditions including removal of impurities from reactor water by the cleanup system, reducing input of impurities causing off-standard conditions by reducing power and reducing the reactor coolant temperature to less than 212°F. The major benefit of reducing the reactor coolant temperature to less than 212°F is to reduce the temperature dependent corrosion rates and thereby provide time for the cleanup system to re-establish proper water quality.

References

(1) FDSAR, Volume I, Section IV-2
(2) (Deleted)
(3) (Deleted)
(4) Licensing Application Amendment 16, Design Requirements Section
(5) (Deleted)
(6) FDSAR, Volume I, Section IV-2.3.3 and Volume II, Appendix H
(7) FDSAR, Volume I, Table IV-2-1
(8) Licensing Application Amendment 34, Question 14
(9) Licensing Application Amendment 28, Item III-B-2
(10) Licensing Application Amendment 32, Question 15
(11) (Deleted)
(12) Licensing Application Amendment 68, Supplement No. 6 Addendum 3
(13) Licensing Application Amendment 16, Page 1



OYSTER CREEK NUCLEAR GENERATING STATION REACTOR VESSEL
PRESSURE/TEMPERATURE LIMITS
FOR UP TO TEN EFFECTIVE FULL POWER YEARS OF CORE OPERATION

Figure 3.3.1

TABLE 3.3.1

PRIMARY COOLANT SYSTEM PRESSURE ISOLATION VALVES

System	Valve No.	Maximum[a] Allowable Leakage
Core Spray System 1	NZ02A	5.0 GPM
	NZ02C	5.0 GPM
Core Spray System 2	NZ02B	5.0 GPM
	NZ02D	5.0 GPM

Footnote:

[a] 1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

5. Test differential pressure shall not be less than 150 psid.

Order dated: April 20, 1981

3.4 EMERGENCY COOLING

Applicability: Applies to the operating status of the emergency cooling systems.

Objective: To assure operability of the emergency cooling systems.

Specifications:

A. Core Spray System

1. The core spray system shall be operable at all times with irradiated fuel in the reactor vessel, except as otherwide specified in this section.

2. The absorption chamber water volume shall be at least 82,000 $ft.^3$ in order for the core spray system to be considered operable.

3. If one core spray system loop or its core spray header ΔP instrumentation becomes inoperable during the run mode, the reactor may remain in operation for a period not to exceed 7 days provided the remaining loop has no inoperable components and is demonstrated daily to be operable.

4. If one of the redundant active loop components in the core spray system becomes inoperable during the run mode, the reactor may remain in operation for a period not to exceed 15 days provided the other similar component in the loop is demonstrated daily to be operable. If two of the redundant active loop components become inoperable, the limits of Specification 3.4.A shall apply.

5. During the period when one diesel is inoperable, the core spray equipment connected to the operable diesel shall be operable.

6. If Specifications 3.4.A.3, 3.4.A.4, and 3.4.A.5 are not met, the reactor shall be placed in the cold shutdown condition. If the core spray system becomes inoperable, the reactor shall be placed in the cold shutdown condition and no work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the top of the active fuel.

7. If necessary to accomplish maintenance or modifications to the core spray systems, their power supplies or water supplies, reduced system availability is permitted when the reactor is: (a) maintained in the cold shutdown condition or (b) in the refuel mode with the reactor coolant system maintained at less than 212°F and vented, and (c) no work is performed on the reactor vessel and connected systems that could result in lowering the reactor water level to less than 4'8" above the top of the active fuel. Reduced Core Spray System Availability is minimally defined as follows:

a. At least one core spray pump, and system components necessary to deliver rated core spray to the reactor vessel, must remain operable to the extent that the pump and any necessary valves can be started or operated from the control room or from local control stations.

b. The fire protection system is operable, and

c. These systems are demonstrated to be operable on a weekly basis.

8. If necessary to accomplish maintenance or modifications to the core spray systems, their power supplies or water supplies, reduced system availability is permitted when the reactor is in the refuel mode with the reactor coolant system maintained at less than 212°F or in the startup mode for the purposes of low power physics testing. Reduced core spray system availability is defined as follows:

a. At least one core spray pump in each loop, and system components necessary to deliver rated core spray to the reactor vessel, must remain operable to the extent that the pump and any necessary valves in each loop can be started or operated from the control room or from local control stations.

b. The fire protection system is operable and,

c. Each core spray pump and all components in 3.4.A.8a are demonstrated to be operable every 72 hours.

9. If Specifications 3.4.A.7 and 3.4.A.8 cannot be met, the requirements of Specification 3.4.A.6 will be met and work will be initiated to meet minimum operability requirements of 3.4.A.7 and 3.4.A.8.

10. The core spray system is not required to be operable when the following conditions are met:

a. The reactor mode switch is locked in the "refuel" or "shutdown" position.

b. (1) There is an operable flow path capable of taking suction from the condensate storage tank and transferring water to the reactor vessel, and

(2) The fire protection system is operable.

c. The reactor coolant system is maintained at less than 212°F and vented.

d. At least one core spray pump, and system components necessary to deliver rated core spray flow to the reactor vessel,

must remain operable to the extent that the pump and any necessary valves can be started or operated from the control room or from local control stations, and the torus is mechanically intact.

e. (1) No work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the top of the active fuel and the condensate storage tank level is greater than thirty (30) feet (360,000 gallons). At least two redundant systems including core spray pumps and system components must remain operable as defined in d. above.

OR

(2) The reactor vessel head, fuel pool gate, and separator-dryer pool gates are removed and the water level is above elevation 117 feet.

NOTE: When filling the reactor cavity from the condensate storage tank and draining the reactor cavity to the condensate storage tank, the 30 foot limit does not apply provided there is sufficient amount of water to complete the flooding operation.

B. Automatic Depressurization System

1. Five electromatic relief valves of the automatic depressurization system shall be operable when the reactor water temperature is greater than 212°F and pressurized above 110 psig, except as specified in 3.4.B.2. The automatic pressure relief function of these valves (but not the automatic depressurization function) may be inoperable or bypassed during the system hydrostatic pressure test required by ASME Code Section XI, IS-500 at or near the end of each ten year inspection interval.

2. If at any time there are only four operable electromatic relief valves, the reactor may remain in operation for a period not to exceed 3 days provided the motor operated isolation and condensate makeup valves in both isolation condensers are demonstrated daily to be operable.

3. If Specifications 3.4.B.1 and 3.4.B.2 are not met; reactor pressure shall be reduced to 110 psig or less, within 24 hours.

4. The time delay set point for initiation after coincidence of low-low-low reactor water level and high drywell pressure shall be set not to exceed two minutes.

C. Containment Spray System and Emergency Service Water System

1. The containment spray system and the emergency service water system shall be operable at all times with irradiated fuel in

the reactor vessel, except as specified in Specifications 3.4.C.3, 3.4.C.4, 3.4.C.6 and 3.4.C.8.

2. The absorption chamber water volume shall not be less than 82,000 ft^3 in order for the containment spray and emergency service water system to be considered operable.

3. If one emergency service water system loop becomes inoperable, its associated containment spray system loop shall be considered inoperable. If one containment spray system loop and/or its associated emergency service water system loop becomes inoperable during the run mode, the reactor may remain in operation for a period not to exceed 7 days provided the remaining containment spray system loop and its associated emergency service water system loop each have no inoperable components and are demonstrated daily to be operable.

4. If a pump in the containment spray system or emergency service water system becomes inoperable, the reactor may remain in operation for a period not to exceed 15 days provided the other similar pump is demonstrated daily to be operable. A maximum of two pumps may be inoperable provided the two pumps are not in the same loop. If more than two pumps become inoperable, the limits of Specification 3.4.C.3 shall apply.

5. During the period when one diesel is inoperable, the containment spray loop and emergency service water system loop connected to the operable diesel shall have no inoperable components.

6. If primary containment integrity is not required (see Specification 3.5.A), the containment spray system may be made inoperable.

7. If Specifications 3.4.C.3, 3.4.C.4, 3.4.C.5 or 3.4.C.6 are not met, the reactor shall be placed in the cold shutdown condition. If the containment spray system or the emergency service water system becomes inoperable, the reactor shall be placed in the cold shutdown condition and no work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the top of the active fuel.

8. The containment spray system may be made inoperable during the integrated primary containment leakage rate test required by Specification 4.5, provided that the reactor is maintained in the cold shutdown condition and that no work is performed on the reactor or its connected systems which could result in lowering the reactor level to less than 4'8" above the top of the active fuel.

D. <u>Control Rod Drive Hydraulic System</u>

1. The control rod drive (CRD) hydraulic system shall be operable when the reactor water temperature is above 212°F except as specified in 3.4.D.2 below.

2. If one CRD hydraulic pump becomes inoperable when the reactor water temperature is above 212°F, the reactor may remain in operation for a period not to exceed 7 days provided the second CRD hydraulic pump is operating and is checked at least once every 8 hours. If this condition cannot be met, the reactor water temperature shall be reduced to <212°F.

E. Core Spray and Containment Spray Pump Compartments Doors

The core spray and containment spray pump compartments doors shall be closed at all times except during passage in order to consider the core spray system and the containment spray system operable.

F. Fire Protection System

1. The fire protection system shall be operable at all times with fuel in the reactor vessel except as specified in Specification 3.4.F.2.

2. If the fire protection system becomes inoperable during the run mode, the reactor may remain in operation provided both core spray system loops are operable with no inoperable components.

Bases:

This specification assures that adequate emergency core cooling capability is available when the core spray system is required. Based on the loss-of-coolant analysis for the worst line break, a core spray of at least 3400 gpm is required within 35 seconds to assure effective core cooling.*(1) Thus, if one loop becomes inoperable, the operable loop is capable of providing cooling to the core and the reactor may remain in operation for a period of 7 days provided repairs can be completed within that time. The 7 days is based upon the consideration discussed in the bases of Specification 3.2 and the pump operability tests of Specification 4.4. If repairs cannot be made, the reactor is depressurized and vented to prevent pressure buildup and no work is allowed to be performed on the reactor which could result in lowering the water level below 4'8" above the top of active fuel.

Each core spray loop contains redundant active components. Therefore, with the loss of one of these components the system is still capable of supplying rated flow and the system as a whole (both loops) can tolerate an additional single failure of one of its active components and still perform the intended function and prevent clad melt. Therefore, if a redundant active component fails, a longer repair period is justified based on the consideration given in the bases of Specification 3.2. The consideration indicates that for a one out of 4 requirement the time out of service would be

$$\frac{\tau}{1.71} = \frac{30 \text{ days}}{1.71} = 17.5 \text{ days}$$

*Core Spray System 2 is required to deliver 3640 gpm.

Specification 3.4.A.5 ensures that if one diesel is out of service for repair, the core spray system loop on the other diesel must be operable with no components out of service. This ensures that the loop can perform its intended function, even assuming one of its active components fails. If this condition is not met, the reactor is placed in a condition where core spray is no longer required.

When the reactor is in the shutdown or refueling mode and the reactor coolant system is less than 212°F and vented and no work is being performed that could result in lowering the water level to less than 4'8" above the core, the likelihood of a leak or rupture leading to uncovering of the core is very low. The only source of energy that must be removed is decay heat and one day after shutdown this heat generation rate is conservatively calculated to be not more than 0.6% of rated power. Sufficient core spray flow to cool the core can be supplied by one core spray pump or one of the two fire protection system pumps under these conditions. When it is necessary to perform repairs on the core spray system components, power supplies or water sources, Specification 3.4.A.7 permits reduced cooling system capabiity to that which could provide sufficient core spray flow from two independent sources. Manual initiation of these systems is adequate since it can be easily accomplished within 15 minutes during which time the temperature rise in the reactor will not reach 2200°F.

In order to allow for certain primary system maintenance, which will include control rod drive repair, LPRM removal/installation, reactor leak test, etc., (all performed according to approved procedure), Specification 3.4.A.8 requires the availability of an additional core spray pump in an independent loop, while this maintenance is being performed the likelihood of the core being uncovered is still considered to be very low, however, the requirement of a second core spray pump capable of full rated flow and the 72 hour operability demonstration of both core spray pumps is specified.

Specification 3.4.A.10 allows the core spray system to be inoperable in the cold shutdown or refuel modes if the reactor cavity is flooded and the spent fuel pool gates are removed and a source of water supply to the reactor vessel is available. Water would then be available to keep the core flooded.

The relief valves of the automatic depressurization system enable the core spray system to provide protection against the small break in the event the feedwater system is not active.

The containment spray system is provided to remove heat energy from the containment in the event of a loss-of-coolant accident. The flow from one pump in either loop is more than ample to provide the required heat removal capability(2). The emergency service water system provides cooling to the containment spray heat exchangers and, therefore, is required to provide the ultimate heat sink for the energy release in the event of a loss-of-coolant accident. The emergency service water pumping requirements are those which correspond

to containment cooling heat exchanger performance implicit in the containment cooling description. Since the loss-of-coolant accident while in the cold shutdown condition would not require containment spray, the system may be deactivated to permit integrated leak rate testing of the primary containment while the reactor is in the cold shutdown condition.

The control rod drive hydraulic system can provide high pressure coolant injection capabilty. For break sizes up to 0.002 ft^2, a single control rod drive pump with flow of 110 gpm is adequate for maintaining the water level nearly five feet above the core, thus alleviating the necessity for auto-relief actuation(3).

The core spray main pump compartments and containment spray pump compartments were provided with water-tight doors(4). Specification 3.4.E ensures that the doors are in place to perform their intended function.

Similarly, since a loss-of-coolant accident when primary containment integrity is not being maintained would not result in pressure build-up in the drywell or torus, the system may be made inoperable under these conditions. This prevents possible personnel injury associated with contact with chromated torus water.

References

(1) Licensing Application, Amendment 34, Question 1

(2) Licensing Application, Amendment 32, Question 3

(3) Licensing Application, Amendment 18, Question 1

(4) Licensing Application, Amendment 18, Question 4

3.5 CONTAINMENT

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

Objective: To assure the integrity of the primary and secondary containment system.

Specification: A. Primary Containment

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

   a. Maximum water volume - 92,000 ft^3
   b. Minimum water volume - 82,000 ft^3
   c. Maximum water temperature

      (1) During normal power operation - 95°F

      (2) During testing which adds heat to the suppression pool, the water temperature shall not exceed 10F° above the normal power operation limit specified in (1) above. In connection with such testing, the pool temperature must be reduced to below the normal power operation limit specified in (1) above within 24 hours.

      (3) The reactor shall be scrammed from any operating condition if the pool temperature reaches 110°F. Power operation shall not be resumed until the pool temperature is reduced below the normal power operation limit specified in (1) above.

      (4) During reactor isolation conditions, the reactor pressure vessel shall be depressurized to less than 180 psig at normal cooldown rates if the pool temperature reaches 120°F.

2. Maintenance and repair, including draining of the suppression pool, may be performed provided that the following conditions are satisfied:

   a. The reactor mode switch is locked in the refuel or shutdown position.

b. (1) There is an operable flow path capable of taking suction from the condensate storage tank and transferring water to the reactor vessel, and

(2) The fire protection system is operable.

c. The reactor coolant system is maintained at less than 212°F and vented.

d. At least one core spray pump, and system components necessary to deliver rated core spray flow to the reactor vessel, must remain operable to the extent that the pump and any necessary valves can be started or operated from the control room or from local control stations, and the torus is mechanically intact.

e. (1) No work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the top of the active fuel and the condensate storage tank level is greater than thirty (30) feet (360,000 gallons). At least two redundant systems including core spray pumps and system components must remain operable as defined in d. above.

or

(2) The reactor vessel head, fuel pool gate, and separator-dryer pool gates are removed and the water level is above elevation 117 feet.

NOTE: When filling the reactor cavity from the condensate storage tank and draining the reactor cavity to the condensate storage tank, the 30 foot limit does not apply provided there is a sufficient amount of water to complete the flooding operation.

3. 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 low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5 Mwt.

a. With one or more of the containment isolation valves shown in Table 3.5.2 inoperable:

(1) Maintain at least one isolation valve operable in each affected penetration that is open and within 4 hours (48 hours for the traversing in-core probe system) either;

(a) Restore the inoperable valve(s) to operable status or

(b) Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolation position, or

(c) Isolate each affected penetration by use of at least one closed manual valve or blind flange.

(2) An inoperable containment isolation valve of the shutdown cooling system may be opened with a reactor water temperature equal to or less than 350°F in order to place the reactor in the cold shutdown condition. The inoperable valve shall be returned to the operable status prior to placing the reactor in a condition where primary containment integrity is required.

4. Reactor Building to Suppression Chamber Vacuum Breaker System

a. Except as specified in Specification 3.5.A.4.b below, two reactor building to suppression chamber vacuum breakers in each line shall be operable at all times when primary containment integrity is required. The set point of the differential pressure instrumentation which actuates the air-operated vacuum breakers shall not exceed 0.5 psid. The vacuum breakers shall move from closed to fully open when subjected to a force equivalent of not greater than 0.5 psid acting on the vacuum breaker disc.

b. From the time that one of the reactor building to suppression chamber vacuum breaker is made or found to be inoperable, the vacuum breaker shall be locked closed and reactor operation is permissible only during the succeeding seven days unless such vacuum breaker is made operable sooner, provided that the procedure does not violate primary containment integrity.

c. If the limits of Specification 3.5.4.4.a are exceeded, reactor shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 24 hours.

5. Pressure Suppression Chamber - Drywell Vacuum Breakers

a. When primary containment is required, all suppression chamber - drywell vacuum breakers shall be operable except during testing and as stated in Specification 3.5.A.5.b and c, below. Suppression chamber - drywell vacuum breakers shall be considered operable if:

(1) The valve is demonstrated to open from closed to fully open with the applied force at all valve positions not exceeding that equivalent to 0.5 psi acting on the suppression chamber face of the valve disk.

(2) The valve disk will close by gravity to within not greater than 0.10 inch of any point on the seal surface of the disk when released after being opened by remote or manual means.

(3) The position alarm system will annunciate in the control room if the valve is open more than 0.10 inch at any point along the seal surface of the disk.

b. Two of the fourteen suppression chamber - drywell vacuum breakers may be inoperable provided that they are secured in the closed position.

c. One position alarm circuit for each operable vacuum breaker may be inoperable for up to 15 days provided that each operable suppression chamber - drywell vacuum breaker with one defective alarm circuit is physically verified to be closed immediately and daily during this period.

6. After completion of the startup test program and demonstration of plant electrical output, the primary containment atmosphere shall be reduced to less than 4.0% O_2 with nitrogen gas within 24 hours after the reactor mode selector switch is placed in the run mode. Primary containment deinerting may commence 24 hours prior to a scheduled shutdown.

7. If specifications 3.5.A.1.a, b, c(1) and 3.5.A.2 through 3.5.A.5 cannot be met, reactor shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

8. Shock Suppressors (Snubbers)

a. All safety related snubbers are required to be operable whenever the systems they protect are required to be operable except as noted in 3.5.A.8.b and c below.

b. With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to operable status.

c. If the requirements of 3.5.A.8.a and 3.5.A.8.b cannot be met, declare the protected system inoperable and follow the appropriate action statement for that system.

d. An engineering evaluation shall be performed to determine if the components protected by the snubber(s) were adversely affected by the inoperability of the snubber prior to returning the system to operable status.

B. Secondary Containment

1. Secondary containment integrity shall be maintained at all times unless all of the following conditions are met:

a. The reactor is subcritical and Specification 3.2.A is met.

b. The reactor is in the cold shutdown condition.

c. The reactor vessel head or the drywell head are in place.

d. No work is being performed on the reactor or its connected systems in the reactor building which could result in inadvertent releases of radioactive material.

e. No operations are being performed in, above, or around the spent fuel storage pool that could cause release of radioactive materials.

1.1 Upon the accidental loss of secondary containment integrity, restored secondary containment integrity within 4 hours, or:

a. During Power Operation:

(1) Have the reactor mode switch in the shutdown mode position within the following 24 hours.

(2) Cease all work on the reactor or its connected systems in the reactor building which could result in inadvertent releases of radioactive materials.

(3) Cease all operations in, above or around the Spent Fuel Storage Pool that could cause release of radioactive materials.

b. During refueling:

(1) Cease fuel handling operations or activities which could reduce the shutdown margin (excluding reactor coolant temperature changes).

(2) Cease all work on the reactor or its connected systems in the reactor building which could result in inadvertant releases of radioactive materials.

(3) Cease all operations in, above or around the Spent Fuel Storage Pool that could cause release of radioactive materials.

2. Two separate and independent standby gas treatment system circuits shall be operable when secondary containment is required except as specified by Specifications 3.5.B.3.

3. With one standby gas treatment system circuit inoperable:

a. During Power Operation:

(1) Demonstrate the operability of the other standby gas treatment system circuit within 2 hours, and

(2) Continue to demonstrate the operability of the standby gas treatment system circuit once per 24 hours until the inoperable standby gas treatment circuit is returned to operable status.

(3) Restore the inoperable standby gas treatment circuit to operable status within 7 days or be subcritical with reactor coolant temperature less than 212°F within the next 36 hours.

b. During Refueling:

(1) Demonstrate the operability of the redundant standby gas treatment system within 2 hours, and

(2) Continue to demonstrate the operability of the redundant standby gas treatment system once per 7 days until the inoperable system is returned to operable status.

(3) Restore the inoperable standby gas treatment system to operable status within 30 days or cease all spent fuel handling, core alterations or operation that could reduce the shutdown margin (excluding reactor coolant temperature changes).

4. If Specifications 3.5.B.2 and 3.5.B.3 are not met, reactor shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours and the condition of Specification 3.5.B.1 shall be met.

Bases:

Specifications are placed on the operating status of the containment systems to assure their availability to control the release of any radioactive materials from irradiated fuel in the event of an accident condition. The primary containment system (1) provides a barrier against uncontrolled release of fission products to the environs in the event of a break in the reactor coolant systems.

Whenever the reactor coolant water temperature is above 212°F, failure of the reactor coolant system would cause rapid expulsion of the coolant from the reactor with an associated pressure rise in the primary containment. Primary containment is required, therefore, to contain the thermal energy of the expelled coolant and fission products which could be released from any fuel failures resulting from the accident. If the reactor coolant is not above 212°F, there would be no pressure rise in the containment. In addition, the coolant cannot be expelled at a rate which could cause fuel failure to occur before the core spray system restores cooling to the core. Primary containment is not needed while performing low power physics tests since procedures and the Rod Worth Minimizer would limit rod 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 off-site doses well below 10 CFR 100 limits.

The absorption chamber water volume provides the heat sink for the reactor coolant system energy released following the loss-of-coolant accident. The core spray pumps and containment spray pumps are located in the corner rooms and due to their proximity to the torus, the ambient temperature in

those rooms could rise during the design basis accident. Calculations (7) made, assuming an initial torus water temperature of 100°F and a minimum water volume of 82,000 ft.^{3}, indicate that the corner room ambient temperature would not exceed the core spray and containment spray pump motor operating temperature limits, and, therefore, would not adversely affect the long term core cooling capability. The maximum water volume limit allows for an operating range without significantly affecting accident analyses with respect to free air volume in the absorption chamber. For example, the containment capability (8) with a maximum water volume of 92,000 ft^3 is reduced by not more than 5.5% metal-water reaction below the capability with 82,000 ft^3.

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 depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

The technical specifications allow for torus repair work or inspections that might require draining of the suppresion pool when all irradiated fuel is removed or when the potential for draining the reactor vessel has been minimized. This specification also provides assurance that the irradiated fuel has an adequate cooling water supply for normal and emergency conditions with the reactor mode switch in shutdown or refuel whenever the suppression pool is drained for inspection or repair.

The purpose of the vacuum relief valves is to equalize the pressure between the drywell and suppression chamber, and suppression chamber and reactor building so that the containment external design pressure limits are not exceeded.

The vacuum relief system from the reactor building to the pressure suppression chamber consists of two 100% vacuum relief breaker subsystems (2 parallel sets of 2 valves in series). Operation of either subsystem will maintain the containment external pressure less than the external design pressure of the drywell by 2 psi; the external design pressure of the suppression chamber is 1 psi (FDSAR Amendment 15, Section 11).

The capacity of the fourteen suppression chambers to drywell vacuum relief valves is sized to limit the external pressure of the drywell during post-accident drywell cooling operations to the design limit of 2 psi. They are sized on the basis of the Bodega Bay pressure suppression tests.(9) (10) In Amendment 15 of the Oyster Creek FDSAR, Section II, the area of 2920 sq. in. is stated as the minimum area for flow of non-condensible gases from the suppression chamber to the drywell. To achieve this requirement, at least 12 of the 14 vacuum breaker valves (18" diameter) must be operable.

Each suppression chamber drywell vacuum breaker is fitted with a redundant pair of limit switches to provide fail safe signals to panel mounted indicators in the Reactor Building and alarms in the Control Room when

the disks are open more than 0.1" at any point along the seal surface of the disk. These switches are capable of transmitting the disk closed-to-open signal with 0.01" movement of the switch plunger. Continued reactor operation with failed components is justified because of the redundancy of components and circuits and, most importantly, the accessibility of the valve lever arm and position reference external to the valve. The fail-safe feature of the alarm circuits assures operator attention if a line fault occurs.

Convervative estimates of the hydrogen produced, consistent with the core cooling system provided, show that the hydrogen air mixture resulting from a loss-of-coolant accident is considerably below the flammability limit and hence it cannot burn, and inerting would not be needed. However, inerting of the primary containment was included in the proposed design and operation. The 5% oxygen limit is the oxygen concentration limit stated by the American Gas Association for hydrogen-oxygen mixtures below which combustion will not occur.[4] The 4% oxygen limit was established by analysis of the Generation and Mitigation of Combustible Gas Mixtures in Inerted BWR Mark I Containments.[12]

To preclude the possibility of starting up the reactor and operating a long period of time with a significant leak in the primary system, leak checks must be made when the system is at or near rated temperature and pressure. It has been shown [9][10] that an acceptable margin with respect to flammability exists without containment inerting. Inerting the primary containment provides additional margin to that already considered acceptable. Therefore, permitting access to the drywell for the purpose of leak checking would not reduce the margin of safety below that considered adequate and is judged prudent in terms of the added plant safety offered by the opportunity for leak inspection. The 24-hour time to provide inerting is judged to be a reasonable time to perform the operation and establish the required O_2 limit.

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 snubbers required to protect the primary coolant system or any other safety system or component be operable whenever the systems they protect are required to be operable.

The purpose of an engineering evaluation is to determine if the components protected by the snubber were adversely affected by the inoperability of the snubber. This ensures that the protected component remains capable of meeting the designed service. A documented visual inspection will usually be sufficient to determine system operability.

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

Secondary containment[5] 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 and 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 overall containment system, it is required at all times that primary containment is required. Moreover, secondary containment is required during fuel handling operations and whenever work is being performed on the reactor or its connected systems in the reactor building since their operation could result in inadvertent release of radioactive material.

When secondary containment is not maintained, the additional restrictions on operation and maintenance give assurance that the probability of inadvertent releases of radioactive material will be minimized. Maintenance will not be performed on systems which connect to the reactor vessel lower than the top of the active fuel unless the system is isolated by at least one locked closed isolation valve.

The standby gas treatment system (6) filters and exhausts the reactor building atmosphere to the stack during secondary containment isolation conditions, with a minimum release of radioactive materials from the reactor building to the environs.

Two separate filter trains are provided each having 100% capacity.[6] If one filter train becomes inoperable, there is no immediate threat to secondary containment and reactor operation may continue while repairs are being made. Since the test interval for this system is one month (Specification 4.5), the time out-of-service allowance of 7 days is based on considerations presented in the Bases in Specification 3.2 for a one-out-of-two system.

References:

(1) FDSAR, Volume I, Section V-1
(2) FDSAR, Volume I, Section V-1.4.1
(3) FDSAR, Volume I, Section V-1.7
(4) Licensing Application, Amendment 11, Question III-25
(5) FDSAR, Volume I, Section V-2
(6) FDSAR, Volume I, Section V-2.4
(7) Licensing Application, Amendment 42
(8) Licensing Application, Amendment 32, Question 3
(9) Robbins, C. H., "Tests on a Full Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment," GEAP-3596, November 17, 1960.
(10) Bodega Bay Preliminary Hazards Summary Report, Appendix I, Docket 50-205, December 28, 1962.
(11) Report H. R. Erickson, Bergen-Paterson to K. R. Goller, NRC, October 7, 1974. Subject: Hydraulic Shock Sway Arrestors.
(12) General Electric NEDO-22155 "Generation and Mitigation of Combustible Gas Mixtures in Inerted BWR Mark I Containments" June 1982.

(13) Oyster Creek Nuclear Generating Station, Mark I Containment Long-Term Program, Plant Unique Analysis Report, Suppression Chamber and Vent System, MPR-733; August, 1982.
(14) Oyster Creek Nuclear Generating Station, Mark I Containment Long-Term Program, Plant Unique Analysis Report, Torus Attached Piping, MPR-734; August, 1982.

Table 3.5.1

SAFETY RELATED SNUBBERS

DELETED

TABLE 3.5.2

CONTAINMENT ISOLATION VALVES

VALVE FUNCTION/VALVE DESIGNATON	ISOLATION SIGNALS
Main Steam Isolation Valves (NS03A, NS03B, NS04A, NS04B)	1
Main Steam Condensate Drain Valves (V-1-106, V-1-107, V-1-110, V-1-111)	1
Reactor Building Closed Cooling Valves (V-5-147, V-5-166, V-5-167)	2
Instrument Air Valve (V-6-395)	1
Emergency Condenser Vent Valves (V-14-1, V-14-5, V-14-19, V-14-20)	1
Reactor Cleanup Valves (V-16-1, V-16-2, V-16-14, V-16-61)	3
Shutdown Cooling Valves (V-17-19, V-17-54)	3
Drywell Equipment Drain Tank Valves (V-22-1, V-22-2)	3
Drywell Sump Valves (V-22-28, V-22-29)	3
Drywell and Torus Atmosphere Control Valves (V-27-1, V-27-2, V-27-3, V-27-4, V-28-17, V-28-18, V-23-21, V-23-22, V-28-47, V-23-13, V-23-14, V-23-15, V-23-16, V-23-17, V-23-18, V-23-19, V-23-20)	3
Reactor Recirculation Loop Sample Valves (V-24-29, V-24-30)	1
Torus to Reactor Building Vacuum Relief Valves (V-26-16, V-26-18)	3*
Traversing In-Core Probe System (Tip machine ball valve No. 1, No. 2, No. 3, No. 4)	3

1)Reactor Isolation Signals as shown in Table 3.1.1
2)Low-Low Reactor Water Level and High Drywell Pressure; or Low-Low-Low Reactor Water Level.
3)Primary Containment Isolation Signals as shown in Table 3.1.1

*Valves automatically reset to provide vacuum relief

3.6 Radioactive Effluents

Applicability: Applies to the radioactive effluents of the facility.

Objective: To assure that radioactive material is not released to the environment in an uncontrolled manner and to assure that the radioactive concentrations of any material released is kept to a practical minimum and in any event, within the limits of 10 CFR 20.

Specification:

A. Plant Stack Effluents

(1) The maximum release rate of gross activity, except iodines and particulates with half lives longer than eight days, shall be limited in accordance with the following equation:

$$Q = \frac{0.21}{E} \text{ Ci/sec.}$$

where Q is the stack release rate (Ci/sec) of gross activity and E is the average gamma energy per disintegration (MeV/dis).

(2) The maximum release rate of iodines and particulates with half lives longer than eight days shall not exceed 4 μCi/sec.

(3) Radiogases released from the stack shall be continuously monitored except for the short time during monitor filter changes. If this specification cannot be met, the reactor shall be placed in the isolated condition.

B. Discharge Canal Effluents

(1) The release of radioactive liquid effluents shall be limited such that the concentration of radionuclides in the discharge canal at the site boundary shall not at any time exceed the concentrations given in Appendix B, Table II, Column 2, of 10 CFR 20 and notes 1 through 5 thereto.

(2) Radioactive liquid effluent being released into the discharge canal shall be continuously monitored, or, if the monitor is inoperative, two independent samples of any tank to be discharged shall be taken, one prior to discharge and one near the completion of discharge, and two station personnel shall independently check valving prior to discharge radioactive liquid effluents.

C. Radioactive Liquid Storage

The maximum amount of radioactivity, excluding tritium, noble gases, and those isotopes with half lives shorter than three days, contained in the radwaste storage tanks outside the radwaste building shall not exceed 10.0 curies. If this activity exceeds 5.0 curies, then the stored liquid will be recycled to tanks within the radwaste facility until the level is reduced below 5.0 curies.

D. Reactor Coolant Radioactivity

The concentration of the total iodine in the reactor coolant shall not exceed 8.0 μCi/gm. If this specification cannot be met, the reactor shall be placed in the cold shutdown condition.

E. Liquid Radioactive Waste Control

Equipment installed for the treatment of liquid wastes shall be used if release of an untreated batch would result in concentrations in excess of 20% of the limits given in Section 3.6.B.(1).

F. Annual Gaseous Release Limits

1. The average release rate of noble gases from the site during any calendar year shall be limited by the following equations:

for beta air dose:

$$(3.17\ E04) \times (3.6\ E\text{-}08) \times \sum_i Qi\ Ni <= 20$$

for gamma air dose:

$$\sum_i Qi\ Mi <= 10$$

Where:

$\sum_i$ denotes summation over all isotopes detected

3.17 E04 = conversion factor pCi-yr/Ci-sec

3.6 E-08 = X/Q at site boundary 569 M SE.

Qi = Average release rate of isotope i, in Ci/yr

Ni = dose conversion factor for beta air dose, mrad-m(3)/pCi-yr. from Table 3.6-1

Mi = dose conversion factor for gamma air dose, mrad/Ci from Table 3.6-1

2. The average release rates of radioiodines and radioactive materials in particulate form released in gaseous effluents from the site during any calendar year shall be limited by the following equation:

$$(3.17\ E\text{-}02)\sum_i[Rii\ \ (4.8\ E\text{-}08 \times Qis + 2.3\ E\text{-}05 \times Qiv) +$$

$$(Rgi + Rvi)\ (5.5\ E\text{-}09 \times Qis + 1.0E\text{-}07 \times Qiv)] <= 15$$

Where:

$\sum_i$ denotes summation over all isotopes detected

3.17 E-02 = conversion factor, uCi-yr/Ci-sec

Rii = dose factor for inhalation, mrem-m(3)/uCi-yr, Table 3.6-2

Rgi = dose factor for ground plane exposure, m(2) -mrem-sec/ uCi-yr. Table 3.6-2

Rvi = dose factor for vegetation consumption m(2) -mrem-sec/ uCi-yr. Table 3.6-2

4.8 E-08 = X/Q at 890m SE for stack releases (Ref. 13)

2.3 E-05 = X/Q at 890m SE for vent releases (Ref. 13)

5.5 E-09 = D/Q at 890m SE for stack releases (Ref. 16)

1.0 E-07 = D/Q at 890m SE for vent releases (Ref. 16)

Qis = average release rate of isotope i from the stack in Ci/yr

Qiv = average release rate of isotope i from the vent in Ci/yr

Note: The Rvi for tritium should be multiplied by X/Q rather than by D/Q as is done for all other nuclides.

Bases: Some radioactive material is released from the plant under controlled conditions as part of the normal operation of the facility. Other radioactive material not normally intended for release could be inadvertently released in the event of certain accident conditions within the facility. Therefore, limits have been placed on the above types of radioactive materials to assure not exceeding the limits of 10 CFR 20 for the former type and the guideline limits of 10 CFR 100 for the latter type.

Radioactive gases from the reactor pass through the steam lines to the turbine and then to the main condenser where they are extracted by the air ejector, passed through 30-minute holdup piping and released via the plant stack. The limits of release and radioactive material from the plant stack have been calculated using meteorological data from an instrumented 400 ft tower at the plant site. The analysis of this onsite meteorological data shows that the expected composition of radiogases after 30 minutes holdup in the off-gas system, a continuous release of 0.3 Ci/sec would not result in a whole body radiation dose exceeding the 10 CFR 20 value of 0.5 rem[2] per year. The Holland plume rise model with no correction factor was used in the calculation of the effect of momentum and buoyancy of a continuously emitted plume.

Independent dose calculations for several locations offsite have been made by the AEC staff. The method utilized onsite meteorological data developed by the licensee and utilized diffusion assumptions appropriate to the site. The method is described in Section 7-5.2.5 of "Meteorology and Atomic Energy - 1968, "equation 7.63 being used. The results of these calculations were equivalent to those generated by the licensee provided the average gamma energy per disintegration for the assumed noble gas mixture with a 30-minute hold up is 0.7 MeV per disintegration. Based on these calculations, a maximum release rate limit

of gross activity, except for iodines and particulates with half lives longer than eight days, in the amount of 0.21 $\bar{E}$ curies per second will not result in offsite annual doses in excess of the limits specified in 10 CFR 20. The $\bar{E}$ determination need consider only the average gamma energy per disintegration since the controlling whole body dose is due to the cloud passage over the receptor and not cloud submersion in which the beta dose could be additive.

Annual average ground level air concentration was calculated[2] using the 400 ft site weather data. The maximum calculated off site concentration at ground level for a continuous release rate of 1 curie/second was found to be about 1.0×10^{-9} μCi/cc. This maximum occurs about 1-1/2 miles north of the plant stack. Adjustment of the 1 curie/second release rate to the stack emission of 0.3 Ci/sec to limit the ground level concentration to the MPC_a of 1×10^{-10} μCi/cc for Iodine 131 gives an allowable release rate of approximately 0.003 Ci/sec. Further adjustment of this rate by a factor of 700 in consideration of the milk production and consumption mode of exposure gives the allowable stack release rate of 4μCi/sec set forth in the specification.

Continuous monitoring of radiogases provides the means for obtaining information on stack release[4] for demonstrating compliance with the stack release rate limits. In the event continuous monitoring is not available, the reactor is isolated from the turbine condenser and, therefore, is isolated from the plant stack. The isolation would normally be expected to be completed within 8 hours.

It is recognized that a precise determination of environmental dose from a certain emission from the stack is only possible by direct measurement. Such information will be provided by the environmental monitoring program (Section 4.6) conducted at and around the site. If the stack emission ever reaches a level such that it is measurable in the environment, such measurements will provide a basis for adjusting the proposed stack limit long before the effect in the environment is of any concern for permissible dose. In this regard, it is important to realize that not averaging emission rate over a period of one calendar year as permitted by 10 CFR 20 represents a very large safety margin between conditions at any one instant (any minute, hour or day) and the long term dose of interest.

The radioactive liquid effluents from the Oyster Creek Station will be controlled on a batch basis with each batch being processed by such method or methods appropriate for the quality and quantity of materials determined to be present. Those batches in which the radioactivity concentrations are sufficiently low to allow release to the discharge canal are diluted with condenser circulating water in order to achieve the allowable concentrations set forth in the specifications[6]. The radioactive liquids will be sampled and analyzed for radioactivity prior to release to the discharge canal, thus providing a means for obtaining information on effluents to be released so that appropriate release rates will be established.

"The radioactivity concentration limits for the liquid effluents set forth in Specification 3.6.B.(1) are based on the limits contained in 10 CFR 20, Appendix B, Table II, Column 2. By excluding averaging for any time period, a margin is maintained between releases made in conformance with this limit and the limit specified in 10 CFR 20.106.

When discharging on the basis of the limit for a mixture of unidentified isotopes (1×10^{-7} μCi/cc), an estimate of radionuclide concentrations in aquatic biota has been made that correlates the resultant activity levels in the biota with the water limits for each isotope given in 10 CFR 20, Appendix B, Table II, Column 2. Based on conditions of minimum bay flushing and with a circulating water flow rate of 450,000 gpm, the predicted concentration adjacent to the outlet of the discharge canal has a value of 1.5×10^{-12} μCi/cc per μCi/day discharged.[7,8] This represents the concentration in the discharge canal undiluted by dispersion in the bay and based on this value, the average μCi/day release rate that will yield a discharge canal concentration not exceeding 1×10^{-7} μCi/cc is approximately 6.7×10^{4} μCi/day or 25 curies/year. Assuming such releases, which is equivalent to releasing continuously at the limit given in this specification, estimates are presented for clams, crabs, and finfish in reference 9. The estimated concentration is less in each case than that permitted in drinking water for that radioisotope. There are several factors which tend to make the estimates higher than would be expected. First, the estimates of bay concentrations are based on dispersion experiments conducted during a period of minimal dilution. Average dilution should be greater. Second, the recirculation effects assumed are greater than those calculated by the mathematical model that was used to estimate the effects of recirculation.

When discharging on the basis of the limits for identified isotopes, consideration must be given to the reconcentration factors cited in reference 9. A major consideration is that with all batch releases being less than the limit given in 10 CFR 20, Appendix B, Table II, Column 2 for each radioisotope, all periods of time when batch releases are not being made will apply in offsetting the effect of reconcentration. Verification of the adequacy of these limits will be obtained by performance of the environmental monitoring program (Section 4.6). If the releases ever reach a level such that the biota sampling shows an increase in the background levels, such measurements will provide a basis for adjusting the isotopic limits long before the effect in the environment is of any concern for permissible dose."

The noble gas releases are controlled so that the beta air dose is less than or equal to 20 mrad/yr and the gamma air dose is less than or equal to 10 mrad/yr (in accordance with 10 CFR 50 Appendix I) at the site boundary in the direction with the highest X/Q. A X/Q of 3.6 E-08 at 569 m in the SE direction was chosen on the basis of the NRC Appendix I Analysis. The X/Q used is that for releases from the stack, since almost all noble gas releases are from that source. Equations B-1 and B-4 from Regulatory Guide 1.109, Rev. 1 (October 1977) Appendix B, are used to calculate the gamma and beta air doses, respectively. The site specific dose factors, Ni, for gamma air dose were obtained from the NRC RABFIN code and are based on the finite plume dose calculational mode.

The releases of radioiodines and radioactive materials in particulate form are controlled so that the thyroid dose to any real person is less than or equal to 15 mrem/yr, in accordance with the design objectives of 10 CFR 50 Appendix I. The X/Q and D/Q values used are for a distance of 890 m in the SE direction which is the location of the highest potential thyroid dose based on the Oyster Creek Appendix I Analysis (Ref. 12). The pathways considered at this location are stored and fresh fruits and vegetables, inhalation and ground plane

deposition. No milk pathway exists at this location. The meat pathway is insignificant and is not considered (Ref. 12). Equations from NUREG-0133 (Ref. 14) are used to calculate the dose factors, along with dose conversion factors from Regulatory Guide 1.109 (Ref. 15). Where no data was provided in Regulatory Guide 1.109 for thyroid dose conversion factors for certain nuclides, the total body dose conversion factors were used. All calculations are done for a child since this produces the highest dose. (Ref. 12).

"Retaining radioactive liquids on-site in order to permit systematic and complete processing is consistent with maintaining radioactive discharges to the environment as low as practicable. Limiting the stored contents to 10.0 curies of activity assures that even in the extremely unlikely event of simultaneous rupture of all of the tanks, the total activity discharged to the Bay would not be greater than the maximum activity recommended as the limiting condition for operation for the annual total quantity released in effluents that is given in proposed Appendix I to 10 CFR 50. This amount of activity would also be less than half the activity discharged to the Bay in one year if the plant were to discharge continuously with the effluent having a radioactive concentration equal to 10 CFR 20 MPC for unidentified isotopes.

"The main pathway to man for activity deposited in the Bay is through the consumption of aquatic biota since there are no drinking water supplies taken from the Bay. The concentrations that could develop in the canal are reduced rapidly in the Bay (See FDSAR Figure II.4.2). The peak concentrations exist for a relatively short time in the Bay and this combined with the uptake time of the biota could result in only minor increases in the equilibrium levels of radioisotopes in the biota. Isotopes with half lives less than three days are not of concern since there is sufficient delay between production in the plant, discharge by means of this postulated accident and human consumption to preclude their being biologically significant. Tritium and noble gases are excluded also because they are not biologically significant. The requirement to process the tank contents if the acivity inventory exceeds 5.0 curies assures action is taken on a timely basis to avoid reaching or exceeding the limit."

"The primary coolant radioactivity concentration limit of 8.0 μCi total iodine per gram of water was calculated based on a steamline-break accident which is isolated in 10.5 seconds. For this accident analysis, all the iodine in the mass of coolant released in this time period is assumed to be released to the atmosphere at the top of the turbine building (30 meters). By limiting the thyroid dose at the site boundary to a maximum of 30 Rem, the iodine concentration in the primary coolant is back-calculated assuming fumigation meteorology, Pasquill Type F at 1 m/sec. The iodine concentration in the primary coolant resulting from this analysis is 8.4 μCi/gm."

The required use of the equipment installed for the treatment of liquid waste is specified for the purpose of limiting the liquid effluent radioactivity levels to a practical minimum. Twenty percent of the Technical Specifcation limit for release of unidentified isotopes is equivalent to the guide value for design objectives given in the Proposed Appendix I to 10 CFR 50.

References:

(1) FDSAR, Volume I, Section IX-3.3.
(2) Licensing Application, Amendment 13, Meteorological Radiological Evaluation for the Oyster Creek Nuclear Power Station Site.
(3) Deleted.
(4) FDSAR, Volume I, Section VII-6.2.3.
(5) Deleted.
(6) FDSAR, Volume I, Section IX-3.1.1
(7) FDSAR, Volume I, Section II-4.3
(8) Licensing Application, Amendment 11, Question 1-4.
(9) Licensing Application, Amendment 11, Question 1-5.
(10) Deleted
(11) Licensing Application, Amendment 11, Question IV-8.
(12) Evaluation of the Oyster Creek Nuclear Station to demonstrate conformance to the Design Objectives of 10 CFR 50 Appendix I, May 1976, Table 3-10 page 2 of 2.
(13) Meteorological Information and Diffusion Estimates to Conform with Appendix I Requirements: Oyster Creek, July 1976, Table 1.3-11 B.
(14) NUREG-0133, Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants, Draft of August, 1978, Pages 30-33 and 36-37.
(15) Regulatory Guide 1.109, Calculaton of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, Tables E-6, E-9, E-13.
(16) Ref. 13, Table 1.3-13B.

Table 3.6-1

DOSE FACTORS FOR EXPOSURE TO A SEMI-INFINITE CLOUD OF NOBLE GASES

Nuclide	N_i* $\frac{(mrad\text{-}m^3)}{pCi\text{-}yr}$	M_i+ (mrad/Ci)
Kr-83m	2.88E-04	3.18E-08
Kr-85m	1.97E-03	4.28E-06
Kr-85	1.95E-03	7.13E-08
Kr-87	1.03E-02	2.30E-05
Kr-88	2.93E-03	5.83E-05
Kr-89	1.06E-02	4.68E-05
Kr-90	7.83E-03	4.41E-05
Xe-131m	1.11E-03	1.09E-06
Xe-133m	1.48E-03	8.98E-07
Xe-133	1.05E-03	8.26E-07
Xe-135m	7.39E-04	1.25E-05
Xe-135	2.46E-03	7.18E-06
Xe-137	1.27E-02	4.08E-06
Xe-138	4.75E-03	3.65E-05
Ar-41	3.28E-03	4.40E-05

*Source: Regulatory Guide 1.109, Revision 1, October 1977, Table B-1.

+Source: Site specific finite plume gamma air dose factors from NRC RABFIN computer code.

TABLE 3.6-2

THYROID DOSE FACTORS FOR INHALATION (Rii), GROUND PLANE EXPOSURE (Rgi), AND VEGETATION CONSUMPTION (Rvi)

NUCLIDE	Rii*	Rgi**	Rvi**
H-3	1.1E03	0	4.0 E03
C-14	6.7E03	0	1.8 E08
Na-24	1.6E04	1.9E07	3.7 E05
P-32	9.9E04	0	1.3 E08
Cr-51	8.5E01	4.7E06	6.5 E04
Mn-54	9.5E03	1.3E09	1.8 E08
Mn-56	3.1E-01	9.0E05	4.2
Fe-55	7.8E03	0	1.3 E08
Fe-59	1.7E04	2.8E08	3.3 E08
Co-58	3.2E03	3.8E08	2.0 E08
Co-60	2.3E04	2.1E10	1.1 E09
Ni-63	2.8E04	0	1.3 E09
Ni-65	1.6E-01	3.0E05	6.6
Cu-64	1.1	6.1E05	6.8 E03
Zn-65	7.0E04	7.5E08	1.3 E09
Zn-69	8.9E-03	0	3.2 E02
Br-83	4.7E02	4.9 E03	5.7
Br-84	5.5E02	2.0 E05	3.8 E-11
Br-85	2.5E01	0	2.6 E-13
Rb-86	1.1E05	3.4 E02	0
Rb-88	3.7E02	3.3 E04	3.1 E-22
Rb-89	2.9E02	1.2 E05	3.5 E-26
Sr-89	1.7E04	2.3 E04	1.1 E09

TABLE 3.6-2
(cont'd)

Sr-90	6.4E06	0	3.2 E11
Sr-91	4.6	2.2 E06	2.1 E04
Sr-92	5.3E-01	7.8 E05	2.9 E01
Y-90	1.1 E02	4.5 E03	6.2 E02
Y-91m	1.8E-02	1.0 E05	4.2 E-10
Y-91	2.4 E04	1.1 E06	5.0 E05
Y-92	5.8 E-01	1.8 E05	4.5 E-2
Y-93	5.1	1.9 E05	8.5
Zr-95	3.7E04	2.5 E08	7.7 E05
Zr-97	1.6E01	3.0 E06	4.9 E01
Nb-95	6.5E03	1.4 E08	1.1 E05
Mo-99	4.3 E01	4.0 E06	1.9 E06
Tc-99m	5.8 E-02	1.8 E05	1.6 E02
Tc-101	1.1 E-03	2.0 E04	6.9 E-30
Ru-103	1.1 E03	1.1 E08	5.9 E06
Ru-105	5.6E-01	6.4 E05	3.3 E01
Ru-106	1.7 E04	4.2 E08	9.3 E07
Ag-110m	9.1 E03	3.5 E09	1.7 E07
Te-125m	1.9 E03	1.6 E06	9.8 E07
Te-127m	6.1 E03	9.2 E04	3.2 E08
Te-127	2.0 E02	3.0 E03	6.9 E03
Te-129m	6.3 E03	2.0 E07	2.8 E08
Te-129	7.1 E-02	2.6 E04	7.7 E-04
Te-131m	9.8 E01	8.0 E06	1.1 E06

TABLE 3.6-2
(cont'd)

Te-131	1.7E-02	2.9 E04	1.4 E-15
Te-132	3.2E02	1.0 E08	2.5 E08
I-130	1.8 E06	5.5 E06	7.0 E07
I-131	1.6 E07	1.7E 07	2.4 E10
I-132	1.9 E05	1.2 E06	3.4 E03
I-133	3.8 E06	2.4 E06	3.9 E08
I-134	5.1 E04	4.4 E05	2.7 E-03
I-135	7.9 E05	2.6 E06	5.0 E06
CS-134	2.2 E05	6.8 E09	5.5 E09
Cs-136	1.2 E05	1.6 E02	1.6 E08
Cs-137	1.3 E05	1.0 E10	3.4 E09
Cs-138	5.6 E02	3.6 E05	5.8 E-11
Ba-139	5.4 E-02	1.1 E05	1.4 E-03
Ba-140	4.3 E03	2.1 E07	1.6 E07
Ba-141	6.4 E-03	4.1 E04	2.9 E-23
Ba-142	2.8 E-03	4.6 E04	0
La-140	7.5 E01	1.9 E07	3.8 E02
La-142	1.3 E-01	7.4 E05	2.4 E-05
Ce-141	2.9 E03	1.4 E07	4.9 E04
Ce-143	2.9 E01	2.3 E06	1.3 E02
Ce-144	3.6 E05	6.9 E07	6.8 E06
Pr-143	9.1 E02	0	7.3 E03
Pr-144	3.0 E-03	1.8 E03	2.6 E-27
Nd-147	6.8 E02	8.5 E06	4.5 E03

TABLE 3.6-2
(cont'd)

W-187	4.3	2.4 E06	1.7 E04
Np-239	2.3 E01	1.7 E06	1.3 E02

* mrem-m(3)/uCi-yr.

** m(2)-mrem sec/uCi-yr.

NOTE: Where no data was available for the thyroid dose factor in R.G. 1.109, Rev. 1, Tables E-9 or E-13, the total body dose factor was used to calculate Rii or Rvi, as applicable. Rvi factors for iodines were reduced by half based on the assumption that one-half the iodine released is non-elemental. (Per R.G. 1.109, Rev. 1, Page 26)

3.7 AUXILIARY ELECTRICAL POWER

Applicability: Applies to the operating status of the auxiliary electrical power supply.

Objective: To assure the operability of the auxiliary electrical power supply.

Specification: A. The reactor shall not be made critical unless all of the following requirements are satisfied:

1. The following buses or panels energized.

   a. 4160 volt buses 1C and 1D in the turbine building switchgear room.
   b. 460 volt buses 1A2, 1B2, 1A21, 1B21 vital MCC 1A2 and 1B2 in the reactor building switchgear room: 1A3 and 1B3 at the intake structure; 1A21A, 1B21A, 1A21B, and 1B21B and vital MCC 1AB2 on 23'6" elevation in the reactor building; 1A24 and 1B24 at the stack.
   c. 208/120 volt panels 3, 4, 4A, 4B, 4C and VACP-1 in the reactor building switchgear room.
   d. 120 volt protection panel 1 and 2 in the cable room.
   e. 125 volt DC distribution centers C and B, and panel D, Panel DC-F, isolation valve motor control center DC-1 and 125V DC motor control center DC-2.
   f. 24 volt D.C. power panels A and B in the cable room.

2. One 230 KV line is fully operational and switch gear and both startup transformers are energized to carry power to the station 4160 volt AC buses and carry power to or away from the plant.

3. An additional scource of power consisting of one of the following is in service connected to feed the appropriate plant 4160 V bus or buses:
   a. A second 230 KV line fully operational.
   b. One 34.5 KV line fully operational.

4. The station batteries B and C are available for normal service and a battery charger is in service for each battery.

5. Bus tie breakers ED and EC are in the open position.

B. The reactor shall be placed in the cold shutdown position if the availability of power falls below that required by Specification A above, except that the reactor may remain

in operation for a period not to exceed 7 days in any 30 day period if a startup transformer is out of service.

None of the engineered safety feature equipment fed by the remaining transformer may be out of service.

C. Standby Diesel Generators

1. The reactor shall not be made critical unless both diesel generators are operable and capable of feeding their designated 4160 volt buses.

2. If one diesel generator becomes inoperable during power operation, repairs shall be initiated immediately and the other diesel shall be operated at least one hour every 24 hours at greater than 20% rated power until repairs are completed. The reactor may remain in operation for a period not to exceed 7 days in any 30-day period if a diesel generator is out of service. During the repair period none of the engineered safety features normally fed by the operational diesel generator may be out of service or the reactor shall be placed in the cold shutdown condition.

3. If both diesel generators become inoperable during power operation, the reactor shall be placed in the cold shutdown condition.

4. For the diesel generators to be considered operable there shall be a minimum of 14,000 gallons of diesel fuel in the standby diesel generator fuel tank.

Bases: The general objective is to assure an adequate supply of power with at least one active and one standby source of power available for operation of equipment required for a safe plant shutdown, to maintain the plant in a safe shutdown condition and to operate the required engineered safety feature equipment following an accident.

AC power for shutdown and operation of engineered safety feature equipment can be provided by any of four active (two 230 KV and two 34.5 KV lines) and either of two standby (two diesel generators) sources of power. Normally all six sources are available. However, to provide for maintenance and repair of equipment and still have redundancy of power sources the requirement of one active and one standby source of power was established. The plant's main generator is not given credit as a source since it is not available during shutdown. The plant 125V DC power is normally supplied by two batteries, each with two associated full capacity chargers. One charger on each battery is in service at all times with the second charger available in the event of charger failure. These chargers are active sources and supply the normal 125V DC requirements with the batteries and standby sources. (1)

In applying the minimum requirement of one active and one standby source of AC power, since both 230 KV lines are on the same set of towers, either one or both 230 KV lines are considered as a single active source.

The probability analysis in Appendix "L" of the FDSAR was based on one diesel and shows that even with only one diesel the probability of requiring engineered safety features at the same time as the second diesel fails is quite small. This analysis used information on peaking diesels when synchronization was required which is not the case for Oyster Creek. Also the daily test of the second diesel when one is temporarily out of service tends to improve the reliability as does the fact that synchronization is not required.

As indicated in Amendment 18 to the Licensing Application, there are numerous sources of diesel fuel which can be obtained within 6 to 12 hours and the heating boiler fuel in a 75,000 gallon tank on the site could also be used. As indicated in Amendment 32 of the Licensing Application and including the Security System loads, the load requirement for the loss of offsite power would require 12,410 gallons for a three day supply. For the case of loss of offsite power plus loss-of-coolant plus bus failure 9790 gallons would be required for a three day supply. In the case of loss of offsite power plus loss-of-coolant with both diesel generators starting the load requirements (all equipment operating) shown there would not be three days' supply. However, not all of this load is required for three days and, after evaluation of the conditions, loads not required on the diesel will be curtailed. It is reasonable to expect that within 8 hours conditions can be evaluated and the following loads curtailed:

1. One Core Spray Pump
2. One Core Spray Booster Pump
3. One Control Rod Drive Pump
4. One Containment Spray Pump
5. One Emergency Service Water Pump

With these pieces of equipment taken off at 8 hours after the incident it would require a total consumption of 12,840 gallons for a three day supply. Therefore, a minimum technical specification requirement of 14,000 gallons of diesel fuel in the standby diesel generator fuel tank will exceed the engineered safety features operational requirement after an accident by approximately 9%.

References:

(1) Letter, Ivan R. Finfrock, Jr. to the Director of Nuclear Reactor Regulations dated April 14, 1978.

3.8 ISOLATION CONDENSER

Applicability: Applies to operating status of the isolation condenser.

Objective: To assure heat removal capability under conditions of reactor vessel isolation from its normal heat sink.

Specification:

A. The two isolation condenser loops shall be operable during power operation and whenever the reactor coolant temperature is greater than 212°F except as specified in C, below.

B. The shell side of each condenser shall contain a minimum water volume of 22,730 gallons. If the minimum volume cannot be maintained or if a source of makeup water is not available to the condenser, the condenser shall be considered inoperable.

C. If one isolation condenser becomes inoperable during the run mode the reactor may remain in operation for a period not to exceed 7 days provided the motor operated isolation and condensate makeup valves in the operable isolation condenser are demonstrated daily to be operable.

D. If Specification 3.8.A and 3.8.B are not met, or if an inoperable isolation condenser cannot be repaired within 7 days, the reactor shall be placed in the cold shutdown condition.

E. If an isolation condenser inlet (steam side) isolation valve (V-14-30, 31, 32 or 33) becomes or is made inoperable, in the open position during the run mode, the redundant inlet isolation valve shall be demonstrated operable. If the inoperable valve is not returned to service within 4 hours declare the affected isolation condenser inoperable, isolate it and comply with Specification 3.8.C.

F. If an AC motor-operated isolation condenser outlet (condensate return) isolation valve (V-14-36 or 37) becomes or is made inoperable in the open position in the run mode, return the valve to service within 4 hours or declare the affected isolation condenser inoperable, isolate it and comply with Specification 3.8.C.

Basis: The purpose of the isolation condenser is to depressurize the reactor and to remove reactor decay heat in the event that the turbine generator and main condenser is unavailable as a heat sink.[1] Since the shell side of the isolation condensers operate at atmospheric pressure, they can accomplish their purpose when the reactor temperature is sufficiently above 212°F to provide for the heat transfer corresponding to reactor decay heat. The tube side of the isolation condensers form a closed loop with the reactor vessel and can operate without reducing the reactor coolant water inventory.

Each condenser containing a minimum total water volume of 22,730 gallons provides 11,060 gallons above the condensing tubes. Based on scram from a reactor power level of 1950 MWt (the design basis power level for the isolation condensers) the condenser system can accomodate the reactor decay heat[2,3] (corrected for U-239 and NP-239) for 1 hour and 40 minutes without need for makeup water. One condenser with a minimum water volume fo 22,730 gallons can accommodate the reactor decay heat for 45 minutes after scram from 1950 MWt before makeup water is required. In order to accommodate a scram from 1950 MWt and cooldown, a total of 107,500 gallons of makeup water would be required either from the condensate storage tank or from the fire protection system. Since the rated reactor power is 1930 MWt, the above calculations represent conservative estimates of the isolation condenser system capability.

The vent lines from each of the isolation condenser loops to the main steam lines downstream of the main steam lines isolation valves are provided with isolation valves which close automatically on isolation condenser actuation or on signals which close the main steam isolation valves. Radiation monitors on the condenser shell side vents and the associated alarms in the control room are provided to alert the operator of a tube leak in the isolation condenser. High temperature sensors in the isolation condenser and pipe areas cause alarm in the control room to alert the operator of a piping leak in these areas.

Specification 3.8.E allows reduction in redundancy of isolation capability for isolation condenser inlet (steam side) isolation valves. Reaconable assurance of isolation capability is provided by testing the operability of the redundant valve. Specification 3.8.F allows short term inoperability of the AC motor-operated isolation condenser outlet (condensate return) valve. It is not necessary to test the redundant DC motor-operated valve as this valve is normally in the closed position. These specifications permit troubleshooting and repair as well as routine maintenance, such as valve stem packing addition or replacement, to be performed during reactor operation without reducing the redundancy of the isolation condenser heat sink function. The out of service time of 4 hours is consistent with that permitted for primary containment isolation valves.[5]

Either of the two isolation condensers can accomplish the purpose of the system. If one condenser is found to be inoperable, there is no immediate threat to the heat removal capability for the reactor and reactor operation may continue while repairs are being made. Therefore, the time out of service for one of the condensers is based on considerations for a one out of two system.[4] The test interval for operability of the valves required to place the isolation condenser in operation is once/month (Specification 4.8). An acceptable out of service time, T,

is then determined to be 10 days. However, if at the time the failure is discovered and the repair time is longer than 7 days the reactor will be placed in the cold shutdown condition. If the repair time is not more than 7 days the reactor may continue in operation, but as an added factor of conservatism, the motor operated isolation condenser and condensate makeup valves on the operable isolation condenser are tested daily. Expiration of the 7 day period or inability to meet the other specifications requires that the reactor be placed in the cold shutdown condition which is normally expected to take no more than 18 hours. The out of service allowance when the system is required is limited to the run mode in order to require system availability, including redundancy, at startup.

References:

(1) FDSAR, Volume I, Section IV-3.
(2) K. Shure and D.J. Dudziak, "Calculating Energy Release by Fission Products," U.S. AEC Report, WAPD-T-1309, March 1961.
(3) K. Shure, "Fission Product Decay Heat," in U.S. AEC Report, WAPD-BT-24, December 1961.
(4) Specification 3.2, Bases.
(5) Specification 3.5.3.a.1.

3.9 REFUELING

Applicability: Applies to fuel handling operations during refueling.

Objective: To assure that criticality does not occur during refueling.

Specification:

A. Fuel shall not be loaded into a reactor core cell unless the control rod in that core cell is fully inserted.

B. During core alterations the reactor mode switch shall be locked in the REFUEL position.

C. The refueling interlocks shall be operable with the fuel grapple hoist loaded switch set at ≤485 lb. during the fuel handling operations with the head off the reactor vessel. If the frame-mounted auxiliary hoist, the trolley-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 lb.

D. During core alterations the source range monitor nearest the alteration shall be operable.

E. Removal of one control rod or rod drive mechanism may be performed provided that all the following specifications are satisfied.

1. The reactor mode switch is locked in the refuel position.

2. At least two (2) sources range monitor (SRM) channels shall be operable and inserted to the normal operation level. One of the operable SRM channel detectors shall be located in the core quadrant where the control rod is being removed and one shall be located in an adjacent quadrant.

F. Removal of any number of control rods or rod drive mechanisms may be performed provided all the following specifications are satisfied:

1. The reactor mode switch is locked in the refuel position and all refueling interlocks are operable as required in Specification 3.9.C. The refueling interlocks associated with the control rods being withdrawn may be bypassed as required after the fuel assemblies have been removed from the core cell surrounding the control rods as specified in 4, below.

2. At least two (2) source range monitor (SRM) channels shall be operable and inserted to the normal operation level. One of the operable SRM channel detectors shall be located in the core quadrant where a control rod is

being removed and one shall be located in an adjacent quadrant.

3. All other control rods are fully inserted with the exception of one rod which may be partially withdrawn not more than two notches to perform refueling interlock surveillance.

4. The four fuel assemblies are removed from the core cell surrounding each control rod or rod drive mechanism to be removed.

5. The core is subcritical by at least 0.25% Δk, plus equivalent reactivity for the effect of any B_4C settling in inverted tubes present in the core, with the most reactive remaining control rod withdrawn.

6. An evaluation will be conducted for each refuel/reload to ensure that actual core criticality for the proposed order of defueling and refueling is bounded by previous analysis performed to support such defueling and refueling activities, otherwise a new analysis shall be performed.

   The new analysis must show that sufficient conservatism exists for the proposed order of defueling and refueling before such operation shall be allowed to proceed.

G. With any of the above requirements not met, cease core alterations or control rod removal as appropriate, and initiate action to satisfy the above requirements.

Basis: During refueling operations, the reactivity potential of the core is being altered. It is necessary to require certain interlocks and restrict certain refueling procedures such that there is assurance that inadvertent criticality does not occur.

Addition of large amounts of reactivity to the core is prevented by operating procedures, which are in turn backed up by refueling interlocks (1) on rod withdrawal and movement of the refueling platform. When the mode switch is in the "Refuel" 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. With the mode switch in the refuel position only one control rod can be withdrawn (1,2).

The one rod withdrawal interlock may be bypassed in order to allow multiple control rod removal for repair, modifications, or core unloading. The requirements for simultaneous removal of more than one Control rod are more stringent than the requirements for removal of a single control rod, since in the latter

case Specification 3.2.A assures that the core will remain subcritical.

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 773 lbs. in the extended position in comparison to the load limit of 485 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.

The source range monitors provide neutron flux monitoring capabilities with the reactor is in the refueling and shutdown modes (3). Specification 3.9.D assures that the neutron flux is monitored as close as possible to the location where fuel or controls are being moved. Specifications 3.9.E and F require the operability of at least two source range monitors when control rods are to be removed.

REFERENCES:

(1) FDSAR, Volume I, Section VII-7.2.5
(2) FDSAR, Volume I, Section XIII-2.2
(3) FDSAR, Volume I, Section VII-4.2.2 and VII-4.3.1

3.10 CORE LIMITS

Applicability: Applies to core conditions required to meet the Final Acceptance Criteria for Emergency Core Cooling Performance.

Objective: To assure conformance to the peak clad temperature limitations during a postulated loss-of-coolant accident as specified in 10 CFR 50.46 (January 4, 1974) and to assure conformance to the 14.5 KW/ft (for V and VB fuel) and 13.4 KW/ft (for P8x8R fuel) operating limits for local linear heat generation rate.

Specification: A. Average Planar LHGR

During power operation, the average linear heat generation rate (LHGR) of all the rods in any fuel assembly, as a function of average planar exposure, at any axial location shall not exceed:

A.1 Fuel Types V and VB

The product of the maximum average planar LHGR (MAPLHGR) limit shown in Figures 3.10-1 (for 5-loop operation) and 3.10-2 (for 4-loop operation) and the axial MAPLHGR multiplier in Figure 3.10-3.

A.2 Fuel Type P8x8R

The maximum average planar LHGR (MAPLHGR) limit shown in Figure 3.10-4 (for 5-loop operation) and 3.10-5 (for 4-loop operation).

A.3 If at any time during power operation it is determined by normal surveillance that the limiting value for APLHGR is being exceeded, action shall be initiated to restore operation to within the prescribed limits. If the APLHGR is not returned to within the prescribed limits within two (2) hours, action shall be initiated to bring the reactor to the cold shutdown condition within 36 hours. During this period surveillance and corresponding action shall continue until reactor operation is within the prescribed limits at which time power operation may be continued.

B. Local LHGR

During 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:

B.1 Fuel Types V and VB

As calculated by the following equation;

$$LHGR \leq LHGR_d \left[1 - \frac{\Delta P}{P} \max \left(\frac{L}{LT} \right) \right]$$

Where: $LHGR_d$ = Limiting LHGR (=14.5)

$\frac{\Delta P}{P}$ = Maximum Power Spiking Penalty (=0.033 and 0.039 for Fuel Types V and VB respectively)

LT = Total Core Length - 144 inches
L = Axial position above bottom of core

B.2 Fuel Type P8x8R

LHGR $\leq$ 13.4 KW/ft.

B.3 If at any time during operation it is determined by normal surveillance that the limiting value of LHGR is being exceeded, action shall be initiated to restore operation to within the prescribed limits. If the LHGR is not returned to within the prescribed limits within two (2) hours, action shall be initated to bring the reactor to the cold shutdown condition within 36 hours. During this period, surveillance and corresponding action shall continue until reactor operation is within the prescribed limits at which time power operation may be continued.

C. Minimum Critical Power Ratio (MCPR)

During steady state power operation, MCPR shall be greater than or equal to the following:

	APRM STATUS	MCPR Limit
1.	If any two (2) LPRM assemblies which are input to the APRM system and are separated in distance by less than three (3) times the control rod pitch contain a combination of (3) out of four (4) detectors located in either the A and B or C and D levels which are failed or bypassed i.e., APRM channel or LPRM input bypassed or inoperable.	1.40
2.	If any LPRM input to the APRM system at the B, C, or D level is failed or bypassed or any APRM channel is inoperable (or bypassed).	1.40
3.	All B, C, and D LPRM inputs to the APRM system are operating and no APRM channels are inoperable or bypassed.	1.40

When APRM status changes due to instrument failure (APRM or LPRM input failure), the MCPR requirement for the degraded condition shall be met within a time interval of eight (8) hours, provided that the control rod block is placed in operation during this interval.

For core flows other than rated, the nominal value for MCPR shall be increased by a factor of k_f, where k_f is as shown in Figure 3.10-6.

If at any time during power operation it is determined by normal surveillance that the limiting value for MCPR is being exceeded for reasons other than instrument failure, action shall be initiated 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, action shall be initiated to bring the reactor to the cold shutdown condition within 36 hours. During this period, surveillance and corresponding action shall continue until reactor operation is within the prescribed limits at which time power operation may be continued.

Bases:

The Specification for average planar LHGR assures that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the 2200°F limit specified in 10 CFR 50.46 (January 4, 1974) considering the postulated effects of fuel pellet densification.

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 location variations in power distribution within a fuel assembly affect the calculated peak clad temperature by less than ± 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 below the limits specified in 10 CFR 50.46 (January 4, 1974).

The maximum average planar LHGR limits of fuel types V and VB are shown in Figure 3.10-1 for five loop operation and in Figure 3.10-2 for four loop operation, and are the result of LOCA analyses performed by Exxon Nuclear Company utilizing an evaluation model developed by Exxon Nuclear Company in compliance with Appendix K to 10 CFR 50 (1). Operation is permitted with the four-loop limits of Figure 3.10-2 provided the fifth loop has its discharge valve closed and its bypass and suction valves open. In addition, the maximum average planar LHGR limits shown in Figures 3.10-1 and 3.10-2 for Type V and VB fuel were analyzed with 100% of the spray cooling coefficients specified in Appendix K to 10 CFR Part 50 for 7 x 7 fuel. These spray heat transfer coefficients were justified in the ENC Spray Cooling Heat Transfer Test Program (2).

The maximum average planar LHGR limits of fuel type P8x8R are shown in Figure 3.10-4 for five loop operation and in Figure 3.10-5 for four loop operation, and are based on calculations employing the models described in Reference 3. Power operation with LHGR's at or below those shown in Figures 3.10-4 and 3.10-5 assures that the peak cladding temperature following a postulated loss-of-coolant accident will not exceed the 2200°F limit.

The effect of axial power profile peak location for fuel types V and VB is evaluated for the worst break size by performing a series of fuel heat-up calculations. A set of multipliers is devised to reduce the allowable bottom skewed axial power peaks relative to center or above center peaked profiles. The major factors which lead to the lower MAPLHGR limits with bottom skewed axial power profiles are the change in canister quench time at the axial peak location and a deterioration in heat transfer during the extended downward flow period during blowdown. The MAPLHGR multiplier in Figure 3.10-3 shall only be applied to MAPLHGR determined by the evaluation model described in reference 1.

The possible effects of fuel pellet densification are:

1) creep collapse of the cladding due to axial gap formation;
2) increase in the LHGR because of pellet column shortening;
3) power spikes due to axial gap formation; and
4) changes in stored energy due to increased radial gap size.

Calculations show that clad collapse is conservatively predicted not to occur during the exposure lifetime of the fuel. Therefore, clad collapse is not considered in the analyses.

Since axial thermal expansion of the fuel pellets is greater than axial shrinkage due to densification, the analyses of peak clad temperatures do not consider any change in LHGR due to pellet column shortening. Although the formation of axial gaps might produce a local power spike at one location on any one rod in a fuel assembly, the increase in local power density would be on the order of only 2% at the axial midplane. Since small local variations in power distribution have a small effect on peak clad temperature, power spikes were not considered in the analysis of loss-of-coolant accidents[1].

Changes in gap size affect the peak clad temperatures by their effect on pellet clad thermal conductance and fuel pellet stored energy. Treatment of this effect combined with the effects of pellet cracking, relocation and subsequent gap closure are discussed in XN-174. Pellet-clad thermal conductance for Type V and VB fuel was calculated using the GAPEX model (XN-174).

The specification for local LHGR assures that the linear heat generation rate in any rod is less than the limiting linear heat generation rate even if fuel pellet densification is postulated. The power spike penalty for Type V and VB fuel is based on analyses presented in Facility Change Request No. 6 and FDSAR Amendment No. 76, respectively. The analysis

assumes a linearly increasing variation in axial gaps between core bottom and top, and assures with 95% confidence that no more than one fuel rod exceeds the design linear heat generation rate due to power spiking.

The power spike penalty for fuel-type P8x8R is described in Reference 3.

The loss of coolant accident (LOCA) analyses are performed using an initial core flow that is 70% of the rated value. The rationale for use of this value of flow is based on the possibility of achieving full power (100% rated power) at a reduced flow condition. The magnitude of the reduced flow is limited by the flow relationship for overpower scram. The low flow condition for the LOCA analysis ensures a conservative analysis because this initial condition is associated with a higher initial quality in the core relative to higher flow-lower quality conditions at full power. The high quality-low flow condition for the steady-state core operation results in rapid voiding of the core during the blowdown period of the LOCA. The rapid degradation of the coolant conditions due to voiding results in a decrease in the time to boiling transition and thus degradation of heat transfer with consequent higher peak cladding temperatures. Thus, analysis of the LOCA using 70% flow and 102% power provides a conservative basis for evaluation of the peak cladding temperature and the maximum average planar linear heat generation rate (MAPLHGR) for the reactor.

The APRM response is used to predict when the rod block occurs in the analysis of the rod withdrawal error transient. The transient rod position at the rod block and corresponding MCPR can be determined. The MCPR has been evaluated for different APRM responses which would result from changes in the APRM status as a consequence of bypassed APRM channel and/or failed bypassed LPRM inputs. The results for the reference cycle (3) indicate that the steady state MCPR required to protect the minimum transient MCPR of 1.07 is 1.23 or higher for the worst case APRM status condition (APRM STATUS 1). This steady state limit conservatively applies to APRM status 2 and 3. The steady state MCPR values for APRM status conditions 1, 2, and 3 will be evaluated each cycle. In order to provide for a limit which is considered to be bounding to future operating cycles, the limits for each APRM status condition have been conservatively adjusted upward to 1.30. This is also the assumed value for LOCA analysis.

The time interval of eight (8) hours to adjust the steady state MCPR to account for a degradation in the APRM status is justified on the basis of instituting a control rod block which precludes the possibility of experiencing a rod withdrawal error transient since rod withdrawal is physically prevented. This time interval is adequate to allow the operator to either increase the MCPR to the appropriate value or to upgrade the status of the APRM system while in a condition which prevents the possibility of this transient occurring.

The steady-state MCPR limit was selected to provide margin to accommodate transients and uncertainties in monitoring the core operating state, manufacturing, and in the critical power correlation itself[3]. This limit was derived by addition of the ΔCPR for the most limiting abnormal operational transient caused by a single operator error or equipment malfunction to the fuel cladding integrity MCPR limit designated in Specification 2.1.

Transients analyzed each fuel cycle will be evaluated with respect to the steady-state MCPR limit specified in this specification.

The purpose of the K_f factor is to define operating limits at other than rated flow conditions. At less than 100% flow the required MCPR is the product of the operating limit MCPR and the K_f factor. Specifically, the K_f factor provides the required thermal margin to protect against a flow increase transient.

The K_f factor curves shown in Figure 3.10-6 were developed generically using the flow control line corresponding to rated thermal power at rated core flow and are applicable to all BWR/2, BWR/3 and BWR/4 reactors. For the manual flow control mode, the K_f factors were calculated such that at the maximum flow state (as limited by the pump scoop tube set point) and the corresponding core power (along the rated flow control line), the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPR's were calculated at different points along the rated flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR determines the value of K_f.

REFERENCES

(1) XN-75-55-(A), XN-75-55, Supplement 1-(A), XN-75-55. Supplement 2-(A), Revision 2, "Exxon Nuclear Company WREM-Based NJP-BWR ECCS Evaluation Model and Application to the Oyster Creek plant," April 1977.

(2) XN-75-36 (NP)-(A), XN-75-36(NP) Supplement 1-(A), "Spray Cooling Heat Transfer phase Test Results, ENC - 8 x 8 BWR Fuel 60 and 63 Active Rods, Interim Report," October 1975.

(3) NEDO-24195; General Electric Reload Fuel Application for Oyster Creek.

FIGURE 3.10-1
MAXIMUM ALLOWABLE AVERAGE PLANAR
LINEAR HEAT GENERATION RATE
(FIVE LOOP OPERATION)

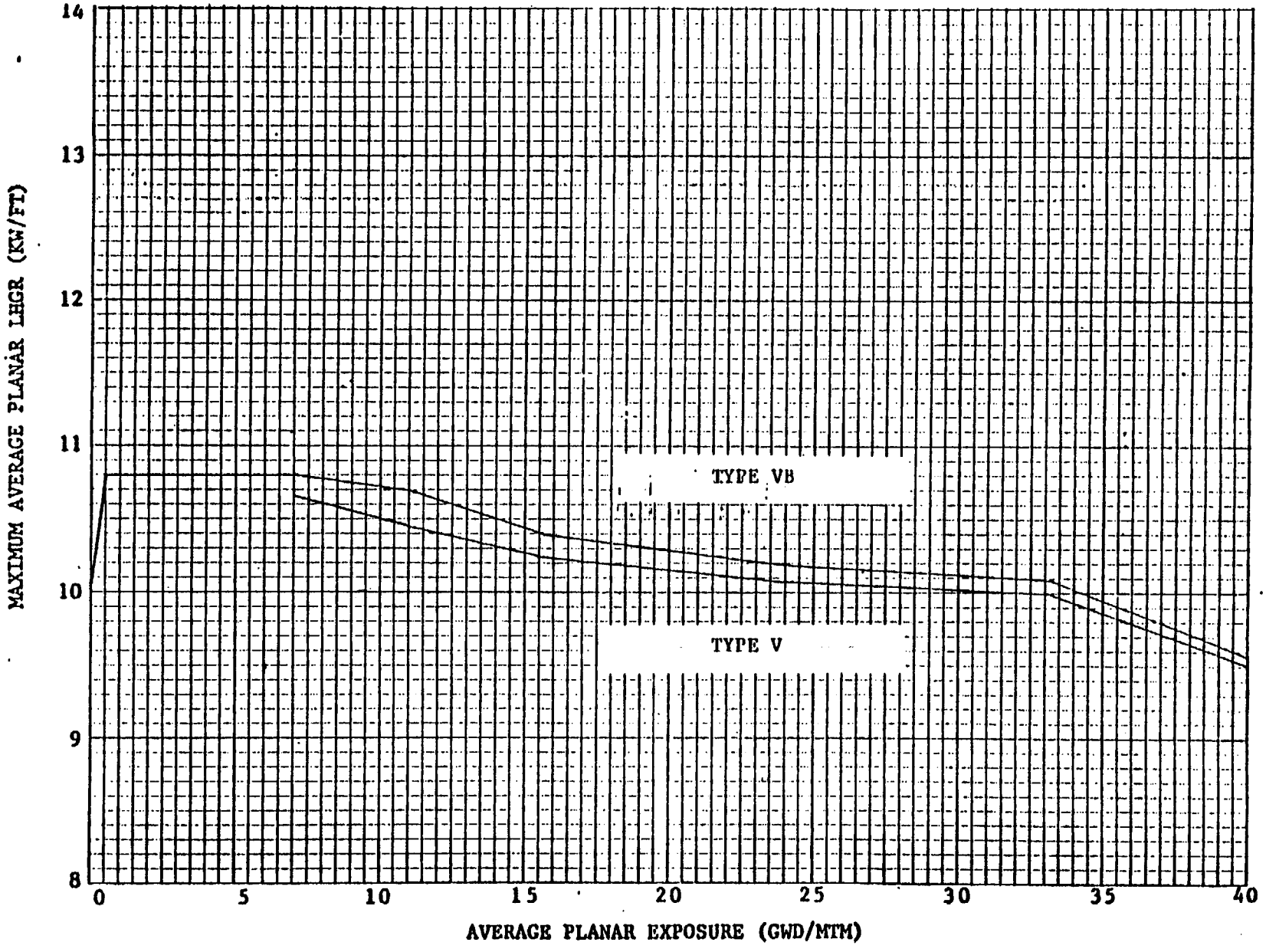


FIGURE 3.10-2
MAXIMUM ALLOWABLE AVERAGE PLANAR
LINEAR HEAT GENERATION RATE
(FOUR LOOP OPERATION)

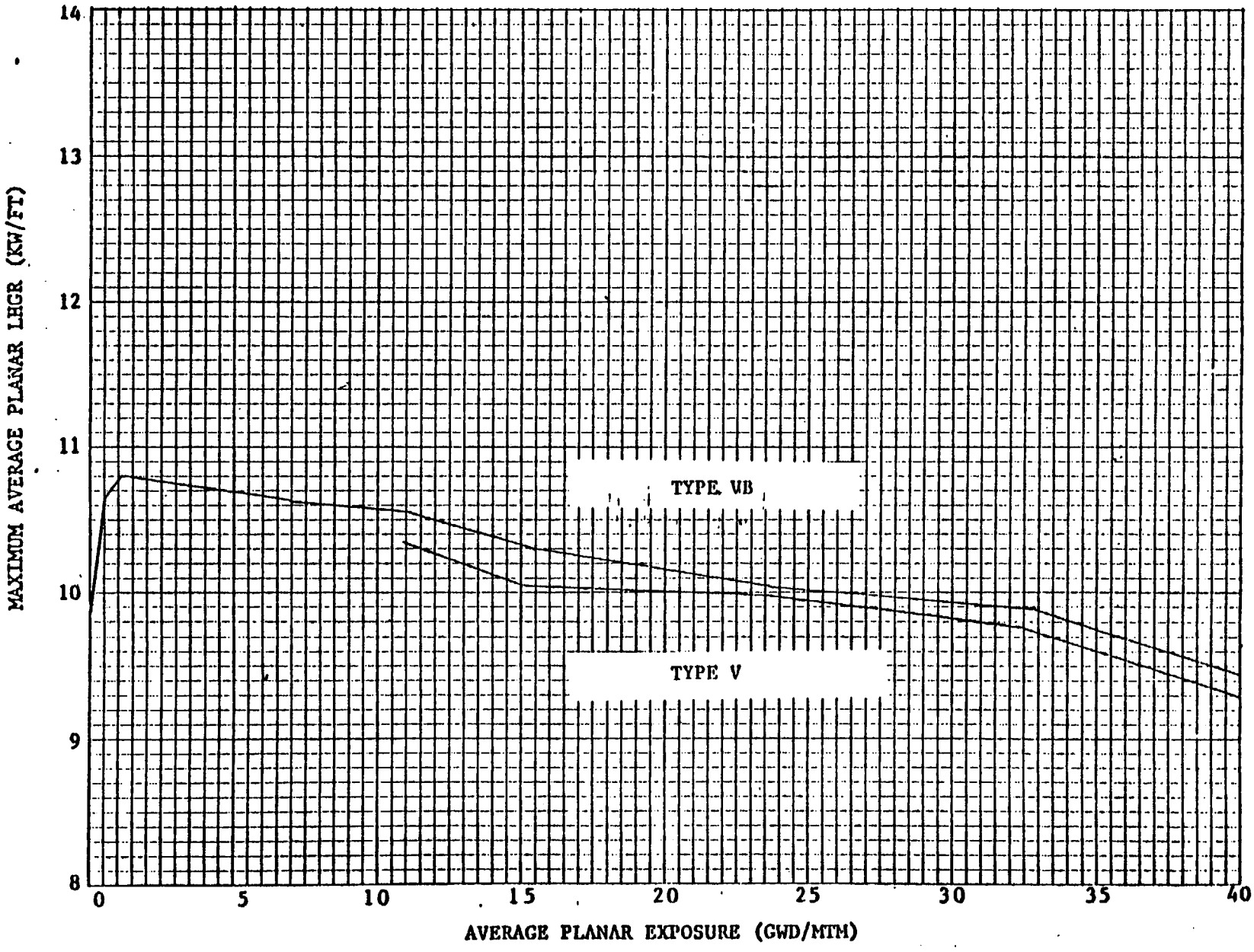


FIGURE 3.10-3

AXIAL MAPLHGR MULTIPLIER
(FOR FUEL TYPES V AND VB ONLY)

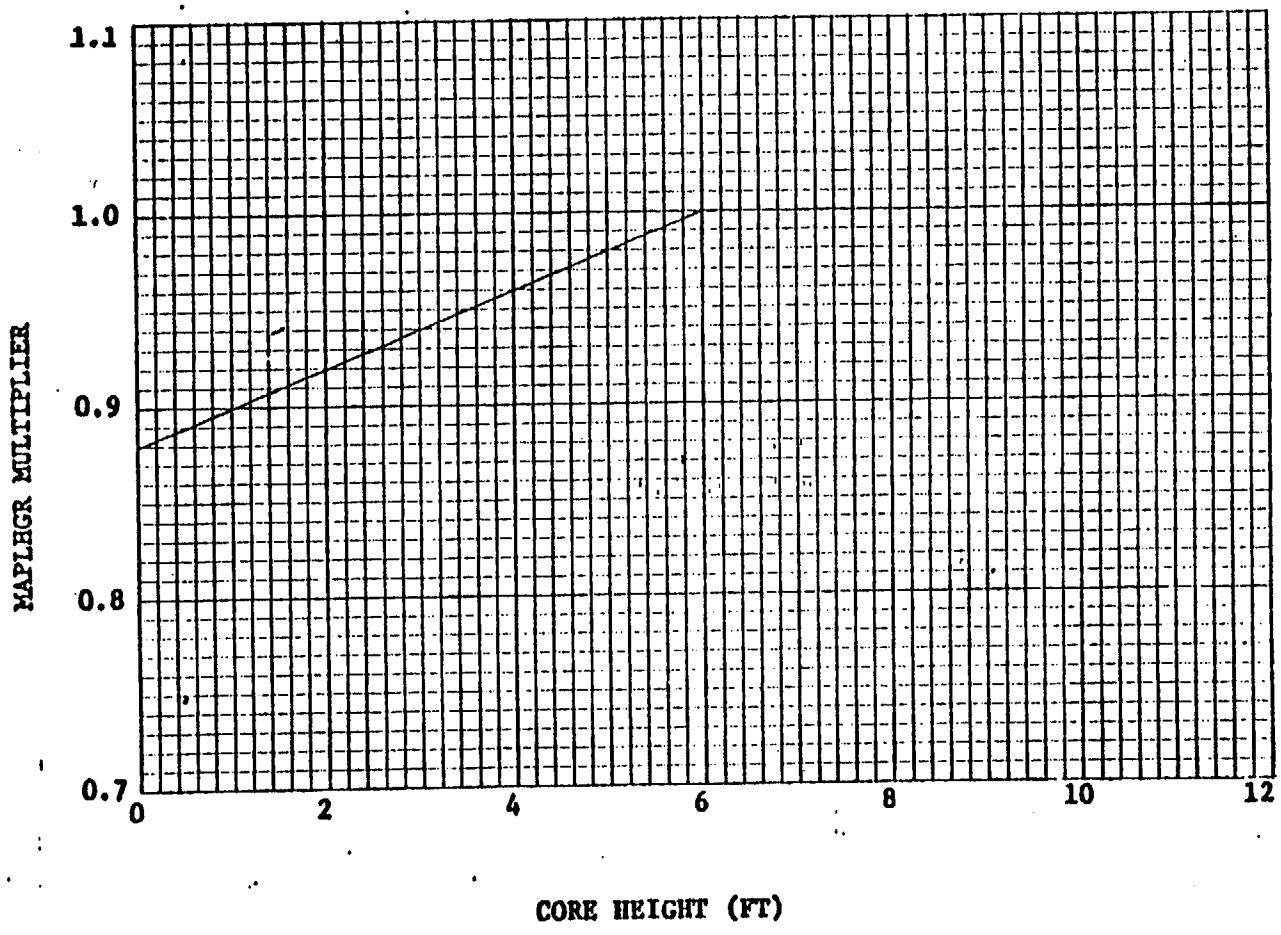


FIG. 3.10-4

MAXIMUM ALLOWABLE AVERAGE PLANAR
LINEAR HEAT GENERATION RATE
(FIVE LOOP OPERATION)

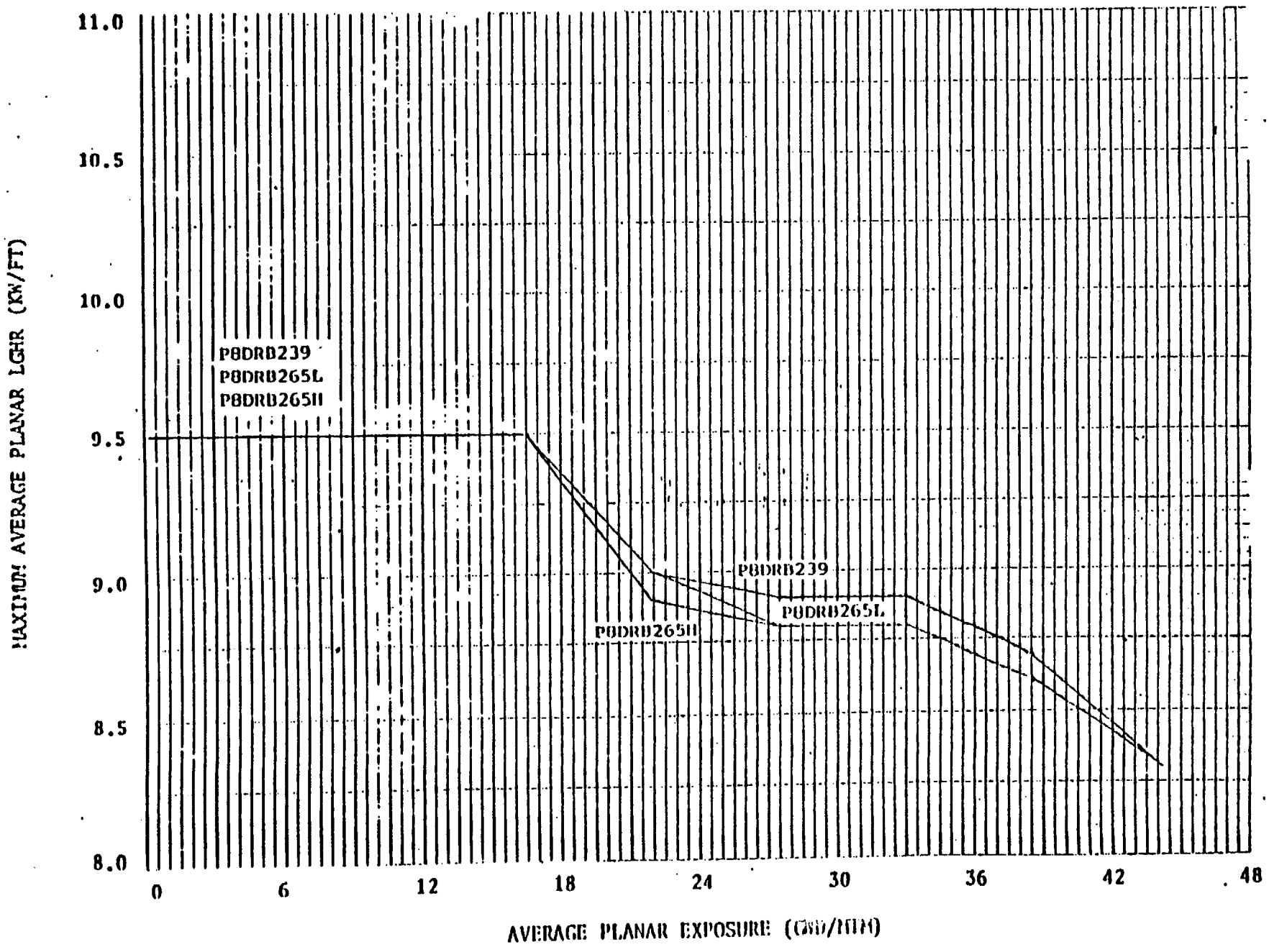


FIGURE 3.10-5

MAXIMUM ALLOWABLE AVERAGE PLANAR
LINEAR HEAT GENERATION RATE
(FOUR LOOP OPERATION)

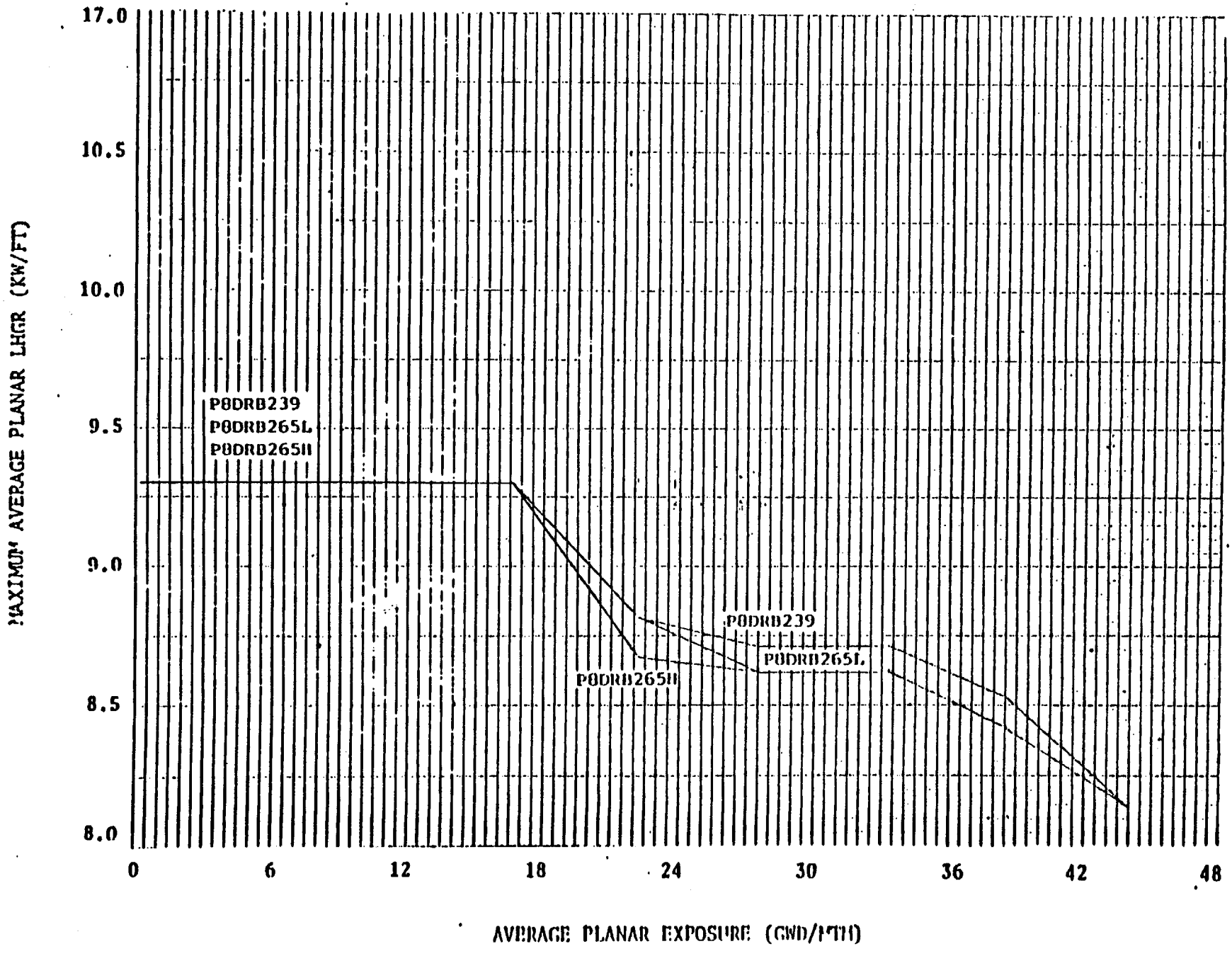
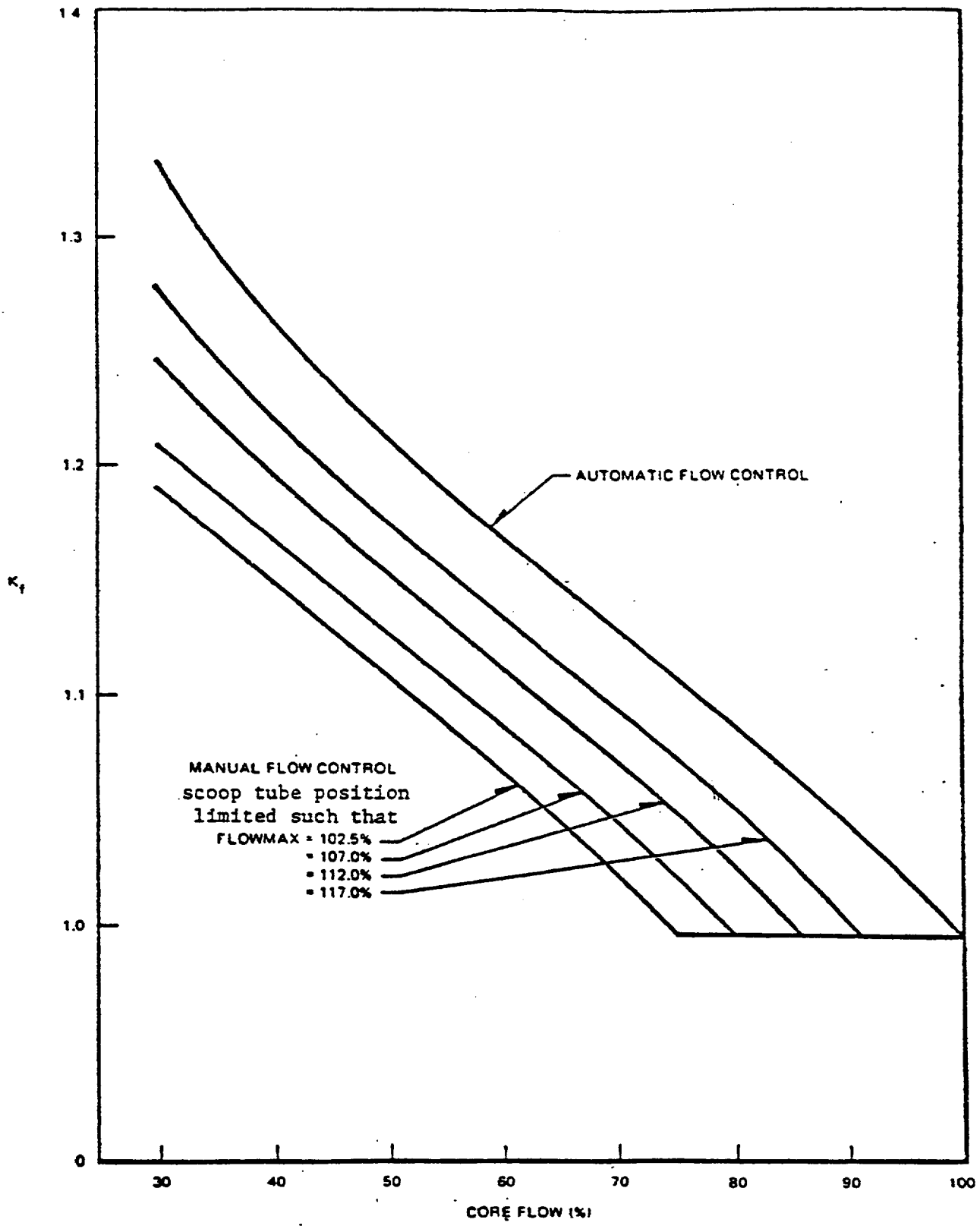


FIGURE 3.10-6 FLOW FACTOR, K_f



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3.12 Fire Protection

Applicability: Applies to the operating status of Fire Detection/Suppression systems and associated instrumentation.

Objective: To assure that fire in safety related areas is detected and suppressed at an early stage so as to minimize fire damage to safety related equipment.

Specification:

A. Fire Detection Instrumentation

1. As a minimum, the fire detection instrumentation for each fire detection area/zone shown in Table 3.12.1 shall be operable, except as otherwise specified in this section.

2. With the number of operable fire detection instruments less than required by Table 3.12.1:

a. Within one hour, establish a fire watch patrol to inspect the area(s)/zone(s) with the inoperable instrument(s) at least once per hour, and

b. Restore the inoperable instrument(s) to operable status within 14 days or prepare and submit a special report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of the inoperability and the plans/schedule for restoring the instrument(s) to operable status.

B. Fire Suppression Water System

1. The Fire Suppression Water System shall be operable with:

a. Two high pressure pumps, each with a capacity of 2000 GPM, with their discharge aligned to the fire suppression header.

b. Automatic initiation logic for each fire pump.

c. An operable flow path capable of taking suction from the fire pond and transferring water through distribution piping with sectionalizing control of valves to the yard hydrant curb valves and the first valve ahead of the water flow alarm device on each sprinkler, hose standpipe or spray system riser required to be operable per specifications 3.12.C and 3.12.D.

2. With one pump inoperable, restore the inoperable equipment to operable status within 7 days or prepare and submit a

Special Report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the plans and procedures to be used to restore the inoperable equipment to operable status or to provide an alternate pump.

3. With no Fire Suppression Water System operable.

a. Within 24 hours establish a backup Fire Suppression Water System, or the reactor shall be placed in the cold shutdown condition.

b. Submit a Special Report to the Commission, in lieu of any other report required by Section 6.9:

(1) By telephone within 24 hours,

(2) Confirmed by telegraph, mailgram or facsimile transmission no later than the first working day following the event, and

(3) In writing within 14 days following the event, outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to operable status.

C. Spray and/or Sprinkler Systems

1. The spray and/or sprinkler systems listed in Table 3.12.2 shall be operable.

2. With one or more of the above required spray and/or sprinkler systems inoperable, within one hour establish a continuous* fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

3. Restore the system to operable status within 14 days or prepare and submit a Special Report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of inoperability and the plans/schedule for restoring the system to operable status.

D. Fire Hose Stations

1. The Fire Hose Stations listed in Table 3.12.3 shall be operable.

2. With a hose station listed in Table 3.12.3 inoperable, within one hour for areas where the inoperable hose station is the primary means of fire suppression otherwise within 24 hours, provide additional lengths of hose at another hose station sufficient to reach the area of the inoperable

hose station, unless the reason for inoperability is a failure of the fire suppression water system. In this event, additional hose lengths are not required and the requirements of Section 3.12.B.3 shall be followed.

3. Restore the affected hose station to operable status within 14 days or prepare and submit a Special Report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of inoperability, and the plans and schedule for restoring the station to operable status.

E. Fire Barrier Penetration Fire Seals

1. All penetration fire barriers protecting safety related fire areas shall be intact except for periods of planned maintenance.

2. With one or more of the above required fire barrier penetrations non-functional, within one hour, either establish a continuous* fire watch on at least one side of the affected penetration, or if the fire detectors on at least one side of the non-functional barrier are operable, establish an hourly fire watch patrol.

3. Restore the non-functional fire barrier penetration(s) to functional status within 7 days or prepare and submit a Special Report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of non-function, the plans and schedule for restoring the fire barrier penetration to operable status.

F. Halon Systems

1. The Halon Systems listed in Table 3.12-4 shall be operable with the storage tanks having at least 95% of full charge weight and 90% of full charge pressure.

2. With a Halon system inoperable within one hour establish a fire watch patrol to inspect the affected area at least once per hour or a continuous* fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged.

3. Restore the system to operable status within 14 days or prepare and submit a Special Report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of inoperability, and the plans/schedule for restoring the system to operable status.

G. Carbon Dioxide (CO_2) System

1. The 4160 Volt Switchgear CO_2 system shall be operable with a minimum level greater than or equal to 1/2 full and a minimum pressure of 275 psig in the associated storage tank.

2. With the CO_2 system inoperable, within one hour establish a continuous* fire watch with backup fire suppression equipment.

3. Restore the system to operable status within 14 days or prepare and submit a Special Report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of inoperability and the plans/schedule for restoring the system to operable status.

H. Yard Fire Hydrants and Hydrant Hose Houses

1. The yard hydrants and associated hose houses listed in Table 3.12.5 shall be operable.

2. With one or more of the yard hydrants or associated hydrant hose houses shown in Table 3.12.5 inoperable, within one hour have sufficient additional lengths of 2 1/2 inch diameter hose located in an adjacent operable hydrant hose house to provide service to the unprotected area(s) if the inoperable fire hydrant or associated hydrant hose house is the primary means of fire suppression; otherwise, provide the additional hose within 24 hours.

3. Restore the hydrant or hose house to operable status within 14 days or prepare and submit a special report to the Commission, in lieu of any other report required by Section 6.9, within the next 30 days outlining the action taken, the cause of the inoperability, and the plans and schedule for restoring the hydrant or hose house to operable status.

*In those areas which represent a radiation, airborn, or industrial safety hazard; an hourly fire watch patrol will be initiated in lieu of the continuous fire watch.

Basis:

Fire Protection systems and instrumentation provide for early detection and rapid extinguishment of fires in safety related areas thus minimizing fire damage. These specifications will assure that in the event of inoperable fire protection equipment, corrective action will be initiated in order to maintain fire protection capabilities during all modes of reactor operation.

The pumps in the fire water suppression system have a capacity of 2000 GPM each assuring an adequate supply of water to fire suppression systems. Fire

suppression water system operability as defined in 3.12.B.1 applies only as pertains to specification 3.12 and is not applicable to other specifications.

Hose stations are provided for manual fire suppression. In the event that a hose station becomes inoperable, additional fire suppression equipment will be provided.

TABLE 3.12.1 FIRE DETECTION INSTRUMENTATION

Fire Area/Zone	Location	Detector Zone	Required # of Detectors
1	Rx.Bldg. 119' elev.	Sprinkler Sys. #10	1 (WFS)
1	" 95' "	NA	24*
1	" 75' "	NA	22*
1	" 75' "	Sprinkler Sys. #11	1 (WFS)
1	" 51' "	RK01/RK02	2
	" 51' "	1 - North	6 +
	" 51' "	2 - North	7 +
	" 51' "	1 - South	6 +
	" 51' "	2 - South	6 +
	" 381/51' "	Shutdown Pump Rm.	7
1	" 23' "	1 - North	6 +
	" 23' "	2 - North	5 +
	" 23' "	1 - South	6 +
	" 23' "	2 - South	6 +
1	" -19' "	NA	4 (1 per corner room.)
3	4160 Swgr. Rm.	Vault	2 (1 in "C" and 1 in "D")
	4160 Swgr. Rm.	Gen. Area	5
	4160 Swgr. Rm.	Battery Rm.	1
4	Cable Spread Rm.	4A-Zone 1	3 +
	"	4A-Zone 2	3 +
	"	4B-Zone 3	4 +
	"	4B-Zone 4	5 +
5	Control Room	Gen. Area	5
	"	A-Zone 1	3 +
	"	A-Zone 2	3 +
	"	B-Zone 1	7*+
	"	B-Zone 2	7*+
	"	C-Zone 1	1 +
	"	C-Zone 2	1 +
	"	Duct	1

TABLE 3.12.1 FIRE DETECTION INSTRUMENTATION

Fire Area/Zone	Location	Detector Zone	Required # of Detectors
6	480 Swgr. Rm.	Zone 1	9 +
	"	Zone 2	8 +
	"	Corridor	1
7	"A" & "B" Battery Rm.	Zone 1	4 +
	"	Zone 2	4 +
	"	Zone 4 (Duct)	1 +
8	MG Set Rm.	NA	1 (WFS)
10	Monitor & Change Rm.	Below Ceiling	2
	"	Above Ceiling	10*
	"	Sprinkler Sys. #12	1 (WFS)
11/3	Condenser Bay	Sprinkler Sys. #2	1 (P.S.)
11/1	Turb. Lube Oil	Deluge Sys. #3	1 (P.S.)
11/2	Turb. Basement South	Sprinkler Sys. 9	1 (WFS)
12	Transformers	Deluge Sys. #1	1 (P.S.)
	"	Deluge Sys. #2	1 (P.S.)
15	Emer. Diesel #1	Thermal	5
	"	Ionization	1
16	Fuel Storage Area	NA	1
17	Emer. Diesel #2	Thermal	5
		Ionization	1
18	Fire Water Pump House	NA	4 +

*No two adjacent detectors may be inoperable.
WFS - Water Flow Switch
P.S. - Pressure Switch
+These detectors actuate automatic suppression systems

TABLE 3.12.2 SPRAY/SPRINKLER SYSTEMS

Fire Area	Location	System
1	Rx. Bldg. 119'	Sprinkler Sys. #10
1	Rx. Bldg. 75'	Sprinkler Sys. #11
1	Rx. Bldg. 51'-N	Deluge Sys. #5
1	" -S	Deluge Sys. $6
1	Rx. Bldg. 23'-N	Deluge Sys. #7
	" -S	Deluge Sys. #8
4	Cable Spread Room	Deluge Sys. #4A
	"	Deluge Sys. #4B
8	MG Set Room	Sprinkler Sys. #4
10	Monitor & Change Rm.	Sprinkler Sys. #12
11	Condenser Bay	Sprinkler Sys. #2
11	Turb. Lube Oil Bay	Deluge Sys. #3
11	Turb. Basement South	Sprinkler Sys. #9
12	Transformers	Deluge Sys. #1
	"	Deluge Sys. #2
18	Fire Water Pump House	Deluge Sys. #9

TABLE 3.12.3 HOSE STATIONS

Fire Area	Zone	Hose Station No.	Locations
11	2	3	Turb. Basement - S
11	2	4	Turb. Basement - S
11	1	8	Turb. Basement - N
11	1	9	Turb. Basement - N
11	3	10	Condenser Bay
11	3	11	Condenser Bay
11	3	12	Condenser Bay
11	3	13	Condenser Bay
1	-	29	Rx Bldg. 23'
1	-	30	Rx Bldg. 23'
1	-	31	Rx Bldg. 23'
1	-	32	Rx Bldg. 23'
1	-	33	Rx Bldg. 23'
1	-	34	Rx Bldg. -19'
1	-	35	Rx Bldg. -19'
1	-	36	Rx Bldg. -19'
1	-	37	Rx Bldg. -19'
1	-	38	Rx Bldg. 51'
1	-	39	Rx Bldg. 51'
1	-	40	Rx Bldg. 51'
1	-	41	Rx Bldg. 51'
1	-	42	Rx Bldg. 75'
1	-	43	Rx Bldg. 75'
1	-	44	Rx Bldg. 75'
1	-	45	Rx Bldg. 75'
1	-	46	Rx Bldg. 95'
1	-	47	Rx Bldg. 95'
1	-	48	Rx Bldg. 95'
1	-	49	Rx Bldg. 95'
1	-	50	Rx Bldg.119'
1	-	51	Rx Bldg.119'
4	-	52	Cable Room
5	-	53	Cable Room
10	1	54	Chem. Lab.
11	2	55	Turb. Basement S

TABLE 3.12.4 HALON SYSTEM

Halon 1301 Sys.	Fire Area	Location	Min. No. of Charged Tanks
1. Battery Room A & B	7	Battery Room (Ofc. Bldg.)	1
Cable Tray Room		Instrument Shop (Ofc. Bldg.)	
2. 480 Volt Switchgear	6	23' Elev. Between Rx. Bldg. & Turb. Bldg	3
3. Control Room Panels	5	Control Room	2

TABLE 3.12-5 HYDRANTS AND HOSE HOUSES

Fire Area	Hydrant No.	Hose House No.	Location
12,15,16,17	3	5	Diesel Gen & Transformer Area
14	2	2	Intake Structure

3.13 ACCIDENT MONITORING INSTRUMENTATION

Applicability: Applies to the operating status of accident monitoring instrumentation.

Objective: To assure operability of accident monitoring instrumentation.

Specification: A. Relief Valve Position Indicators

1. The accident monitoring instrumentation channels shown in Table 3.13.1 shall be operable when the mode switch is in the Startup or Run positions.

2. With the number of operable accident monitoring instrumentation channels less than the Total Number of Channels shown in Table 3.13.1, either restore the inoperable channels to operable status within 7 days, or place the reactor in the shutdown condition within the next 24 hours.

3. With the number of operable accident monitoring instrumentation channels less than the Minimum Channels Operable requirements of Table 3.13.1, either restore the inoperable channel(s) to the operable status within 48 hours, or place the reactor in the shutdown condition within the next 24 hours.

B. Safety Valve Position Indicators

1. During power operation, both primary* and backup** safety valve monitoring instruments are required to be operable except as provided in 3.13.B.2 and 3.13.B.3.

2. If either the primary* or backup** accident monitoring instruments on a valve become inoperable, the primary* accident monitoring instrument on an adjacent valve must be operable, and its set point appropriately reduced.

3. If both the primary* and backup** accident monitoring instruments on a valve become inoperable and the primary* accident monitoring instrument on an adjacent valve is operable, either restore the inoperable channel(s) to an operable status within 7 days, or place the reactor in the shutdown condition within the next 24 hours.

---

* Acoustic Monitor
** Thermocouple

4. If the requirements of Section 3.13.B.2 or 3.13.B.3 cannot be met within 48 hours, place the reactor in the shutdown condition within the next 24 hours.

C. In the event that any of these monitoring channels become inoperable, they shall be made operable prior to startup following the next cold shutdown.

D. Wide Range Torus Water Level Monitor

1. Two wide range torus water level monitor channels shall be continuously indicated in the control room during Power Operation.

2. With the number of operable accident monitoring channels less than the total Number of Channels shown in Table 3.13.1, restore the inoperable channel(s) to Operable status within 7 days or place the reactor in the shutdown condition within the next 24 hours.

3. With the number of operable accident monitoring instrumentation channels less than the Minimum Channels operable requirements of Table 3.13.1, restore the inoperable channel(s) to operable status within 48 hours or place the reactor in the shutdown condition within the next 24 hours.

E. Wide Range Drywell Pressure Monitor

1. Two Wide Range Drywell Pressure monitor channels shall be continuously indicated in the control room during Power Operation.

2. With the number of operable accident monitoring channels less than the total Number of Channels shown in Table 3.13.1, restore the inoperable channel(s) to Operable status within 7 days or place the reactor in the shutdown condition within the next 24 hours.

3. With the number of operable accident monitoring instrumentation channels less than the Minimum Channels operable requirements of 3.13.1, restore the inoperable channel(s) to operable status within 48 hours or place the reactor in the shutdown condition within the next 24 hours.

F. Drywell H_2 Monitor

1. Two drywell hydrogen monitor channels shall be capable of continuously indicating in the control room during power operation.

2. With the number of operable channels less than the total number of channels shown in Table 3.13.1, restore the inoperable channel to operable status within 30 days or place the reactor in the shutdown condition within the next 24 hours.

3. With the number of operable channels less than the minimum channels operable requirements of Table 3.13.1, restore at least one channel to operable status within 7 days or place the reactor in the shutdown condition within the next 24 hours.

BASES

The purpose of the safety/relief valve accident monitoring instrumentation is to alert the operator to a stuck open safety/relief valve which could result in an inventory threatening event.

As the safety valves present distinctly different concerns than those related to relief valves, the technical specifications are separated as to the actions taken upon inoperability. Clearly, the actuation of a safety valve will be immediately detectable by observed increase in drywell pressure. Further confirmation can be gained by observing reactor pressure and water level. Operator action in response to these symptoms would be taken regardless of the acoustic monitoring system status. Acoustic monitors act only to confirm the reseating of the safety valve. In actuality, the operator actions in response to the lifting of a safety valve will not change whether or not the safety valve reseats. Therefore, the actions taken for inoperable acoustic monitors on safety valves are significantly less stringent than that taken for those monitors associated with relief valves.

Should an acoustic monitor on a safety valve become inoperable, setpoints on adjacent monitors will be reduced to assure alarm actuation should the safety valve lift, since it is of no importance to the operator as to which valves lift but only that one has lifted. Analyses, using very conservative blowdown forces and attenuation factors, show that reducing the alarm setpoint on adjacent monitors to <1.4g will assure alarm actuation should the adjacent safety valve lift. Minimum blowdown force considered was 30g with a maximum attenuation of 27dB. In actuality, a safety valve lift would result in considerably larger blowdown force. The maximum attenuation of 27dB was determined based on actual testing of a similar monitoring system installed in a similar configuration.

The operability of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. This capability is consistent with NUREGs 0578 and 0737.

TABLE 3.13.1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
1. Relief Valve Position Indicator (Primary Detector*)	1/valve	1/valve
Relief Valve Position Indicator (Backup Indications**)	1/valve	

* Acoustic Monitor
** Thermocouple
Thermocouple TE 65A can be substituted for thermocouple TE210-43V, W, or X
Thermocouple TE 65B can be substituted for thermocouple TE210-43Y, or Z

2. Wide Range Drywell Pressure Monitor (PT/PR-53 & 54)	2	1
3. Wide Range Torus Water Level Monitor (LT/LR-37 & 38)	2	1
4. Drywell H_2 Monitor	2	1

SECTION 4

SURVEILLANCE REQUIREMENTS

4.1 PROTECTIVE INSTRUMENTATION

Applicability: Applies to the surveillance of the instrumentation that performs a safety function.

Objective: To specify the minimum frequency and type of surveillance to be applied to the safety instrumentation.

Specification: Instrumentation shall be checked, tested, and calibrated as indicated in Tables 4.1.1, and 4.1.2 as per definitions given in Section 1.

Basis: The minimum testing frequency is based on evaluation of unsafe failure rate data and reliability analysis. This, in turn, is based on operating experience at conventional and nuclear power plants. An "unsafe failure" is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is tested or attempts to respond to a bona fide signal. Failures such as blown fuses, faulted amplifiers, faulted cables, etc., which result in "upscale" or "downscale" indication will be easily recognized during operation of the reactor or by observation of the functioning instrumentation system and are not defined unsafe. Furthermore, such failures are, in many cases, revealed by alarm or annunciator action. The functions listed in Table 4.1.1 logically divide into three groups:

a. On-Off sensors that provide a scram function or some other equally important function.

b. Analog devices coupled with a bi-stable trip that provides a scram function or some other vitally important 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 only at shutdown.

Failure rate data for group (a) devices is anailable from many sources, including FARADA, AVCO, UKAEC, AIEE (Dickinson). Nuclear Engr/Gilbert Associates, Ralph M. Parsons, and General Electric Co. Although the data varies somewhat due to environment, the average unsafe failure rate is about 2.5×10^{-6} failure/hr. The variance in failure rate data and the clean environment of atomic power plants indicate that sensor failure rates are smaller than the average for all applications. To

test and calibrate a sensor requires that it be tripped, disconnected from its normal sensing line, and connected to a test line pressure source, than returned to its original state. This task requires an estimated 30 minutes to 1 hour to complete in a thorough and workmanlike manner. Too frequent testing of the fifty-two sensors is a needless burden on plant operators. Consequently, field data will be collected (testing once/month) and used with Figure 4.1.1[1] to adjust the test interval.

Figure 4.1.1 is a plot of the total number of failures r (all sensors) against M=nT(1-R) for a family of values of τ with a confidence level of 0.95, where

n = 52, the total number of sensors

T = Average time the sensors have been in service, hours

R = 0.993, the necessary availability of a sensor.

The value of R is the necessary individual sensor availability that results in a total system availability A. The IEEE Nuclear Safety Group Subcommittee on Reliability has tentatively proposed the goal of A = 0.9999 demonstrated system availbility by operation data. For the one-out-of-two twice logic,[2]

$$R = 1 - \sqrt{\frac{1 - A}{2}} = 1 - \sqrt{\frac{1 - 0.9999}{2}} = 0.993$$

The in-service time T is average hours from initial startup, since sensors are in service even during shutdown.

To adjust the test frequency, furst calculate the M factor, M = 0.36 x T, where T is average hours from initial startup. On Figure 4.1.1, locate the point of intersection of M and r, the number of unsafe failures since startup. The test interval associated with the line to the left of this point will assure an availability of 0.9999.

For example suppose that after 18 months, 2 unsafe failures have occurred.

M = 0.36 x 18 mo x 730 hours/mo. = 4700

To the left of the point (2,4700) is the line for τ=2 months, the test interval resulting in an availability of at least 0.9999. Had no unsafe failures occurred in the same time, τ could have been extended to 3 months.

Testing once/mo is more frequent than is consistent with practicability, but can be tolerated for a limited time to establish predicted failure rates. When justified by actual field data, lengthening the test interval according to

Figure 4.1.1 will maintain an availability of at least 0.9999. The maximum test interval, regardless of field data, will be three months.

Group (b) devices utilize an analog sensor followed by an amplifier and bi-stable trip circuit. The sensor and amplifier are active components and a failure would generally result in an upscale signal, a downscale signal, or no signal. These conditions are alarmed so a failure would not go undetected. The bi-stable portion does need to be tested in order to prove that it will assume its tripped state when required. Since the test and calibration equipment is built in, this test can be performed very quickly and more frequently without degrading reliability. With the instrument in the calibrate position, the calibration pot is varied up and down to verify input-output relationship and trip points. The test frequency of once per week has developed principally on the basis of past practice and good judgement, and nothing has developed to indicate tat the frequency should change.

Group (c) devices are active only during a given portion of the operational cycle. For example, the IRM is inactive during full-power operation and active during startup. Thus, the only test that is significant is the one performed just prior to shutdown and startup. The condenser Low Vacuum trip can only be tested during shutdown, and although it is connected into the reactor protection system, it is not required to protect the reactor. Testing at each refueling outage is adequate. The switches for the high temperature main steamline tunnel are not accessible during normal operation because of their location above the main steam lines. Therefore, after initial calibration and in-place operability checks, they will not be tested between refueling shutdowns. Considering the physical arrangement of the piping which would allow a steam leak at any of the four sensing locations to affect the other locations, it is considered that the function is not jeopardized by limiting calibration and testing to refueling outages.

The logic of the instrument safety systems in Table 4.1.1 is such that testing the instrument channels also trips the trip system, verifying that it is operable. However, certain systems require coincident instrument channel trips to completely test their trip systems. Therefore, Table 4.1.2 specifies the minimum trip system test frequency for these tripped systems. This assures that all trip systems for protective instrumentation are adequately tested, from sensors through the trip system.

Every element of electrical circuitry for the reactor protection system is to be verified operable prior to plant startup by functional testing. Parallel elements of circuits which do not permit functional verification of freedom from shorts by routine channel trips are to be verified functional during refueling shutdown.

IRM calibration is to be performed during reactor startup. The calibration of the IRMs during startup will be significant since the IRMs will be relied on for neutron monitoring and reactor protection up to 38.4% of rated power during a reactor startup.

References: (1) "Reliability of Engineered Safety Features as a Function of Testing Frequency," I. M. Jacobs, Nuclear Safety, Volume 9, No. 4, July-August, 1968.

(2) "Reactor Protection System, A Reliability Analysis," I. M. Jacobs, APED-5179, Eng. A-16, June, 1966.

TABLE 4.1.1

MINIMUM CHECK, CALIBRATION AND TEST FEQUENCY FOR PROTECTIVE INSTRUMENTATION

	Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
1.	High Reactor Pressure	N A	1/3 mo.	Note 1	By application of test pressure
2.	High Drywell Pressure (Scram)	N A	1/3 mo.	Note 1	By application of test pressure
3.	Low Reactor Water Level	Note 3	1/3 mo.	Note 1	By application of test pressure
4.	Low-Low Water Level	Note 3	1/3 mo.	Note 1	By application of test pressure
5.	High Water Level in Scram Discharge Volume	N A	1/3 mo.	Note 1	By varying level in switch columns
6.	Low-Low-Low Water Level	N A	1/3 mo.	Note 1	By application of test pressure
7.	High Flow in Main Steamline	1/d	1/3 mo.	Note 1	By application of test pressure
8.	Low Pressure in Main Steamline	N A	1/3 mo.	Note 1	By application of test pressure
9.	High Drywell Pressure (Core Cooling)	1/d		Note 1	By application of test pressure
10.	Main Steam Isolation Valve (Scram)	N A	N A	1/3 mo.	By exercising valve

NOTE 1: Initially once/mo, thereafter according to Fig. 4.1.1, with an interval not less than one month nor more than three months.

NOTE 2: At least daily during reactor power operation, the reactor neutron flux peaking factor shall be estimated and the flow-referenced APRM scram and rod block settings shall be adjusted, if necessary, as specified in Section 2.3, Specifications (1) (a) and (2) (a).

NOTE 3: A daily channel check will be performed using RE 21A and B to verify reactor water level instrumentation header operability. This is valid from November 8, 1985 to the restart from the 11R outage. Otherwise, a daily channel check is required.

Table 4.1.1 (cont'd)

	Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
11.	APRM Level	N A	1/3 d	N A	Output adjustment using operational type heat balance during power operation
	APRM Scram Trips	Note 2	1/wk.	1/wk.	Using built-in calibration equipment during power operation
12.	APRM Rod Blocks	Note 2	1/3 mo.	1/mo.	Upscale and downscale
13.a.	High Radiation in Main Steamline	1/s	1/3 mo.	1/mo.	Using built-in calibration equipment during power operation
b.	Sensors for 13(a)	N A	Each re-fueling outage	N A	Using external radiation source
14.	High Radiation in Reactor Building				
	Operating Floor	1/s	1/3 mo	1/wk	Using gamma source for calibration
	Ventilation Exhaust	1/s	1/3 mo	1/wk	Using gamma source for calibration
15.	High Radiation on Air Ejector Off-Gas	1/s	1/3 mo	1/wk	Using built-in calibration equipment
16.	IRM Level	N A	each startup	N A	
	IRM Scram	*	*	*	Using built-in calibration equipment
17.	IRM Blocks	N A	Prior to startup and shutdown	Prior to startup and shutdown	Upscale and downscale
18.	Condenser Low Vacuum	N A	Each refueling outage	Each refueling outage	

Table 4.1.1 (cont'd)

	Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
19.	Manual Scram Buttons	N A	N A	1/3 mo	
20.	High Temperature Main Steamline Tunnel	N A	Each refueling outage	Each refueling outage	Using heat source box
21.	SRM	*	*	*	Using built-in calibration equipment
22.	Isolation Condenser High Flow ΔP (Steam and Water)	N A	1/3 mo	1/3 mo	By application of test pressure
23.	Turbine Trip Scram	N A		Every 3 months	
24.	Generator Load Rejection Scram	N A	Every 3 months	Every 3 months	
25.	Recirculation Loop Flow	N A	Each refueling outage	N A	By application of test pressure
26.	Low Reactor Pressure Core Spray Valve Permissive	N A	Every 3 months	Every 3 months	By application of test pressure
27.	Scram Discharge Volume (Rod Block)				
	a) Water level high	N A	Each refueling outage	Every 3 months	By varying level in switch column
	b) Scram trip bypass	NA	NA	Each refueling outage	

Table 4.1.1 (cont'd)

	Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
28.	Loss of Power				
	a) 4.16 KV Emergency Bus Undervoltage (Loss of voltage)	Daily	1/18 mos.	1/mo	
	b) 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	Daily	1/18 mos.	1/mo	

*Calibrate prior to startup and normal shutdown and thereafter check 1/s and test 1/wk until no longer required.

Legend:
NA = Not applicable; 1/s = Once per shift; 1/d = Once per day; 1/3d = Once per three days; 1/wk = Once per week; 1/3 mo = Once every 3 months; 1/18 mos. = Once every 18 months.

TABLE 4.1.2

MINIMUM TEST FREQUENCIES FOR TRIP SYSTEMS

Trip System	Minimum Test Frequency
1) Dual Channel (Scram)	Same as for respective instrumentation in Table 4.1.1
2) Rod Block	Same as for respective instrumentation in Table 4.1.1
3) Containment Spray, each trip system, one at a time	1/3 mo. and each refueling outage
4) Automatic Depressurization, each trip system, one at a time	Each refueling outage
5) MSIV Closure, each closure logic circuit independently (1 valve at a time)	Each refueling outage
6) Core Spray, each trip system, one at a time.	1/3 mo. and each refueling outage.
7) Primary Containment Isolation, each closure circuit independently (1 valve at a time)	Each refueling outage
8) Refueling Interlocks	Prior to each refueling operation
9) Isolation Condenser Actuation and Isolation, each trip circuit independently (1 valve at a time)	Each refueling outage
10) Reactor Building Isolation and SGTS Initiation	Same as for respective instrumentation in Table 4.1.1
11) Condenser Vacuum Pump Isolation	Prior to each startup

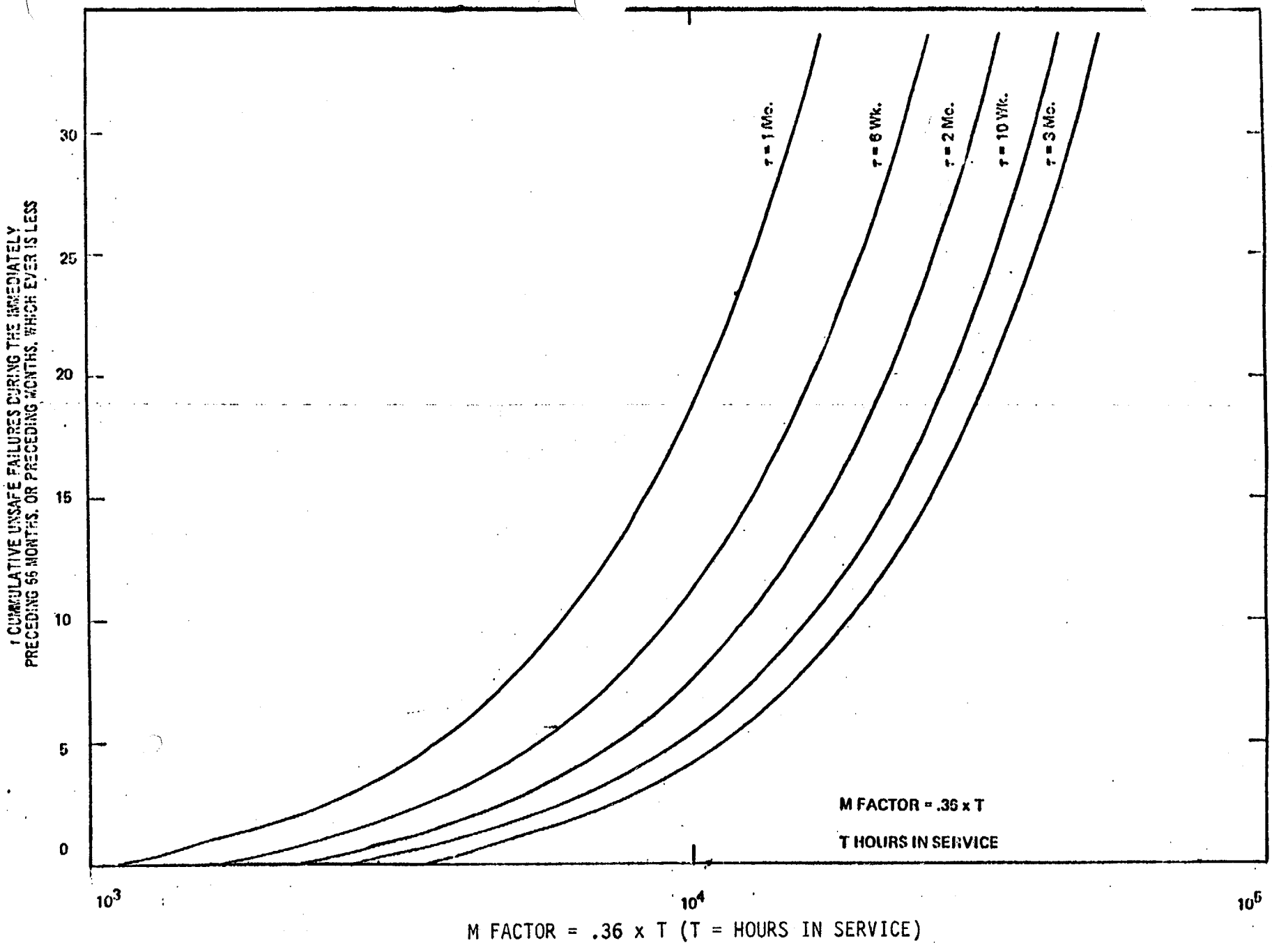

Figure 4.1.1. Failures Versus Time In Service

4.2 REACTIVITY CONTROL

Applicability: Applies to the surveillance requirements for reactivity control.

Objective: To verify the capability for controlling reactivity.

Specification:

A. Sufficient control rods shall be withdrawn following a refueling outage when core alterations were performed to demonstrate with a margin of 0.25% Δk that the core can be made subcritical at any time in the subsequent fuel cycle with the strongest operable control rod fully withdrawn and all other operable rods fully inserted.

B. The control rod drive housing support system shall be inspected after reassembly.

C. 1. After each major refueling outage and prior to resuming power operation, all operable control rods shall be scram time tested from the fully withdrawn position with reactor pressure above 800 psig.

2. Following each reactor scram from rated pressure, the mean 90% insertion time shall be determined for eight selected rods. If the mean 90% insertion time of the selected control rod drives does not fall within the range of 2.4 to 3.1 seconds or the measured scram time of any one drive for 90% insertion does not fall within the range of 1.9 to 3.6 seconds, an evaluation shall be made to provide reasonable assurance that proper control rod drive performance is maintained.

3. Following any outage not initiated by a reactor scram, eight rods shall be scram tested with reactor pressure above 800 psig provided these have not been measured in six months. The same criteria of 4.2.C(2) shall apply.

D. Each partially or fully withdrawn control rod shall be exercised at least once each week. This test shall be performed at least once per 24 hours in the event of power operation is continuing with two or more inoperable control rods or in the event power operation is continuing with one fully or partially withdrawn rod which cannot be moved and for which control rod drive mechanism damage has not been ruled out. The surveillance need not be completed within 24 hours if the number of inoperable rods has been reduced to less than two and if it has been demonstrated that control rod drive mechanism collet housing failure is not the cause of an immovable control rod.

E. Surveillance of the standby liquid control system shall be as follows:

1.	Pump operability	Once/month
2.	Boron concentration determination	Once/month

3.	Functional test	Each refueling outage
4.	Solution volume and temperature check	Once/day

F. At specific power operation conditions, the actual control rod configuration will be compared with the expected configuration based upon appropriately corrected past data. This comparison shall be made every equivalent full power month. The initial rod inventory measurement performed with equilibrium conditions are established after a refueling or major core alteration will be used as base data for reactivity monitoring during subsequent power operation throughout the fuel cycle.

G. The scram discharge volume drain and vent valves shall be verified open at least once per 31 days, except in shutdown mode*, and shall be cycled at least one complete cycle of full travel at least quarterly.

H. All withdrawn control rods shall be determined OPERABLE by demonstrating the scram discharge volume drain and vent valves OPERABLE. This will be done at least once per refueling cycle by placing the mode switch in shutdown and by verifying that:

a. The drain and vent valves close within 30 seconds after receipt of a signal for control rods to scram, and

b. The scram signal can be reset and the drain and vent valves open when the scram discharge volume trip is bypassed.

Basis: The core reactivity limitation (Specification 3.2.A) requires that core reactivity be limited such that the core could be made subcritical at any time during the operating cycle, with the strongest operable control rod fully withdrawn and all other operable rods fully inserted. Compliance with this requirement can be demonstrated conveniently only at the time of refueling. Therefore, the demonstration must be such that it will apply to the entire subsequent fuel cycle. The demonstration is performed with the reactor core in the cold, xenon-free condition and will show that the reactor is sub-critical at that time by at least R + 0.25% Δk with the highest worth operable control rod fully withdrawn.

The value of R is the difference between two calculated values of reactivity of the cold, xenon-free core with the strongest operable control rod fully withdrawn. The reactivity value at the beginning of life is subtracted from the maximum reactivity value anytime later in life to determine R, which must be a positive quantity or its value is conservatively taken as zero. The value of R shall include the potential shutdown margin loss assuming full B_4C settling in all

*These valves may be closed intermittently for testing under administrative control.

possibly inverted tubes present in the core. The value 0.25% Δk in the expression R + 0.25% Δk serves at the beginning of life as a finite, demonstrable shutdown margin. This margin is demonstrated by full withdrawal of the strongest rod and partial withdrawal of a diagonally adjacent rod to a position calculated to insert an R + 0.25% Δk reactivity. Observation of subcriticality in this condition assures subcriticality with not only the strongest rod fully withdrawn but at least an R + 0.25% Δk margin beyond this.

The control rod drive housing support system(2) is not subject to deterioration during operation. However, reassembly must be assured following a partial or complete removal.

The scram insertion times for all control rods(3) will be determined at the time of each refueling outage. The scram times generated at each refueling outage when compared to scram times previously recorded gives a measurement of the functional effects of deterioration for each control rod drive. The more frequent scram insertion time measurements of eight selected rods are performed on a representative sample basis to monitor performance and give an early indication of possible deterioration and required maintenance. The times given for the eight-rod tests are based on the testing experience of control rod drives which were known to be in good condition.

The weekly control rod exercise rest serves as a periodic check against deterioration of the control rod system. Experience with this control rod system has indicated that weekly tests are adequate, and that rods which move by drive pressure will scram when required as the pressure applied is much higher. The frequency of exercising the control rods has been increased under the conditions of two or more control rods which are valved out of service in order to provide even further assurance of the reliability of the remaining control rods.

Pump operability, boron concentration, solution temperature and volume of the standby liquid control system(4) are checked on a frequency consistent with instrumentation checks described in Specification 4.1. Experience with similar systems has indicated that the test frequencies are adequate. The only practical time to functionally test the liquid control system is during a refueling outage. The functional test includes the firing of explosive charges to open the shear plug valves and the pumping of demineralized water into the reactor, to assure operability of the system downstream of the pumps. The test also includes recirculation of liquid control solution to and from the solution tanks.

Pump operability is demonstrated on a more frequent basis. This test consists of recirculation of demineralized water to a test tank. A continuity check of the firing circuit on the shear plug valves is provided by pilot lights in the control room. Tank level and temperature alarms are provided to alert the operator to off-normal conditions.

The functional test and other surveillance on components, along with the monitoring instrumentation, gives a high reliability for standby liquid control system operability.

References

(1) FDSAR, Volume II, Figure III-5-11
(2) FSDAR, Volume I, Section VI-3
(3) FSDAR, Volume I, Section III-5 and Volume II, Appendix B
(4) FSDAR, Volume I, Section VI-4

4.3 REACTOR COOLANT

Applicability: Applies to the surveillance 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. Neutron flux monitors shall be installed in the reactor vessel adjacent to the vessel wall at the core midplane level. The monitors shall be removed and tested at the first refueling outage to experimentally verify the calculated values of integrated neutron flux that are used to determine the NDTT from Figure 3.3.1.

B. Inservice inspection of ASME Code Class 1, Class 2 and Class 3 systems and components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR, Section 50.55a(g), except where specific written relief has been granted by the NRC pursuant to 10 CFR, Section 50.55a(g)(6)(i).

C. Inservice testing of ASME Code Class 1, Class 2 and Class 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR, Section 50.55a(g), except where specific written relief has been granted by the NRC pursuant to 10 CFR, Section 50.55a(g)(6)(i).

D. A visual examination for leaks shall be made with the reactor coolant system at pressure during each scheduled refueling outage or after major repairs have been made to the reactor coolant system in accordance with Article 5000, Section XI. The requirements of specification 3.3.A shall be met during the test.

E. Each replacement safety valve or valve that has been repaired shall be tested in accordance with subsection IWV-3510 of Section XI of the ASME Boiler and Pressure Vessel Code. Setpoints shall be as follows:

Number of Valves	Set Points (psig)
4	1212 ± 12
4	1221 ± 12
4	1230 ± 12
4	1239 ± 12

F. A sample of reactor coolant shall be analyzed at least every 72 hours for the purpose of determining the content of chloride ion and to check the conductivity.

*G. Prmary Coolant System Pressure Isolation Valves Specification:

1. Periodic leakage testing[a] on each valve listed in Table 4.3.1 shall be accomplished prior to exceeding 600 psig reactor pressure every time the plant is placed on the cold shutdown condition for refueling, each time the plant is placed in a cold shutdown condition for 72 hours if testing has not been accomplished in the preceding 9 months, and prior to returning the valve to service after maintenance, repair or replacement work is performed.

H. Reactor Coolant System Leakage

1. Unidentified leakage shall be monitored at least once every 4 hours.

2. Total leakage rate (identified and unidentified) shall be monitored at least once every 8 hours.

3. A channel calibration of the primary containment sump flow integrator and the primary containment equipment drain tank flow integrator shall be conducted at least once per 18 months.

Bases:

Numerous data are available relating integrated flux and the change in Nil-Dectility Transition Temperature (NDTT) in various steels. The base metal has been demonstrated to be relatively insensitive to neutron irradiation (see expected NDT changes in FDSAR Table IV-1-1, and Figures IV-2-9 and IV-2-10). The most conservative data has been used in Specification 3.3. The integrated flux at the vessel wall is calculated from core physics data and will be measured using flux monitors installed inside the vessel. The measurements of the neutron flux at the vessel wall will be used to check and if necessary correct, the calculated data to determine an accurate flux. From this a conservative NDT temperature can be determined. Since no shift will occur until an integrated flux of 10^{17} nvt is reached, the confirmation can be made long before an NDTT shift would occur.

The inspection program will reveal problem areas should they occur, before a leak develops. In addition, extensive visual inspection for leaks will be made on critical systems. Oyster Creek was designed and constructed prior to

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[a] To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

*NRC Order dated April 20, 1981.

the existence of ASME Section XI. For this reason, the degree of access required by ASME Section XI is not generally available and will be addressed as "requests for relief" in accordance with 10 CFR 50.55a(g).

Experience in safety valve operation shows testing in accordance with Section XI of the ASME Boiler and Pressure Vessel Code is adequate to detect failures or deterioration. The tolerance value is specified in Section I of the ASME Code at ±1% of design pressure. An analysis has been performed which shows that with all safety valves set 12 psig higher the safety limit of 1375 psig is not exceeded.

Conductivity instruments continuously monitor the reactor coolant. Experience indicates that a check of the conductivity instrumentation at least every 72 hours is adequate to ensure accurate readings. The reactor water sample will also be used to determine the chloride ion content to assure that the limits of 3.3.E are not exceeded. The chloride ion content will not change rapidly over a period of several days; therefore, the sampling frequency is adequate.

TABLE 4.3.1

PRIMARY COOLANT SYSTEM PRESSURE ISOLATION VALVES

System	Valve No.	Maximum Allowable Leakage [a]
Core Spray System 1	NZ02A	5.0 GPM
	NZ02C	5.0 GPM
Core Spray System 2	NZ02B	5.0 GPM
	NZ02D	5.0 GPM

Footnote:

(a) 1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unaccpetable.

5. Test differential pressure shall not be less than 150 psid.

NRC Order dated April 20, 1981

4.4 EMERGENCY COOLING

Applicability: Applies to surveillance requirements for the emergency cooling systems.

Objective: To verify the operability of the emergency cooling systems.

Specification: Surveillance of the emergency cooling systems shall be performed as follows:

Item	Frequency
A. Core Spray System	
1. Pump Operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.
2. Motor operated valve operability	Once/month
3. Automatic actuation test	Every 3 months
4. Pump compartment water-tight doors closed	Once/week and after each entry
5. Core spray header ΔP instrumentation	
check	Once/day
calibrate	Once/3 months
test	Once/3 months
B. Automatic Depressurization	
1. Valve operability	Every refueling outage
2. Automatic actuation test	Every refueling outage
C. Containment Cooling System	
1. Pump Operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.
2. Automatic actuation test	Every 3 months
3. Pump compartment water-tight doors closed	Once/week and after each entry

Item	Frequency
D. Emergency Service Water System	
1. Pump Operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.
2. Automatic actuation test	Every 3 months
E. Control Rod Drove Hydraulic System	
1. Pump Operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.
F. Fire Protection System	
1. Pump and Isolation valve operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.

Bases: It is during major maintenance or repair that a system's design intent may be violated accidentally. Therefore, a functional test is required after every major maintenance operation. During an extended outage, such as a refueling outage, major repair and maintenance may be performed on many systems. To be sure that these repairs on other systems do not encroach unintentionally on critical standby cooling systems, they should be given a functional test prior to startup.

Motor operated pumps, valves and other active devices that are normally on standby should be exercised periodically to make sure that they are free to operate. Motors on pumps should operate long enough to approach equilibrium temperature to ensure there is no overheat problem. Whenever practical, valves should be stroked full length to ensure that nothing impedes their motion. Engineering judgment based on experience and availability analyses of the type presented in Appendix L of the FDSAR indicates that testing these components more often than once a month over a long period of time does not significantly improve the system reliability. Also, at this frequency of testing wearout should not be a problem through the life of the plant.

During tests of the electromatic relief valves, steam from the reactor vessel will be discharged directly to the absorption chamber pool. Scheduling the tests in conjunction with the refueling outage permits the tests to be run at low pressure thus minimizing the stress on the system.

The control rod drive hydraulic system is normally in operation, thereby providing continuous indication of system operability. A check of flow rate and operability can be made during normal operation.

4.5 CONTAINMENT SYSTEM

Applicability: Applies to the containment system leakage rate, filter efficiency and inerting.

Objective: To verify that the condition of the containment system and the leakage from the containment system are maintained within specified values.

Specification: A. Integrated Primary Containment Leakage Rate Test

1. Integrated leak rate tests shall be performed prior to initial plant operation at the test pressures of 35 psig (P_p) and the test pressure (P_t) of 20 psig to obtain the respective measured leak rates Lm (35) and Lm (20).

2. Subsequent Leakage rate tests shall be performed without preliminary leak detection surveys or leak repairs immediately prior to or during the test, at an initial pressure of approxiamtely 20 psig.

3. Leak repairs, if necessary to permit integrated leakage rate testing, shall be preceded by local leakage measurements. The leakage rate difference, prior to and after repair when corrected to P_t shall be added to the final integrated leakage rate result.

4. Closure of the containment isolation valves for the purpose of the test shall be accomplished by the means provided for normal operation of the valves.

5. The test duration shall not be less than 24 hours for integrated leak rate measurements, but shall be extended to a sufficient period of time to verify, by measuring the quantity of air required to return to the starting point (or other methods of equivalent sensitivity), the validity and accuracy of the leakage rate results.

B. Acceptance Criteria

1. The maximum allowable leakage rate Lp shall not exceed 1.0 weight percent of the contained air per 24 hours at the test pressure of 35 psig (P_p).

2. The allowable test leak rate L_t (20) shall not exceed the lesser value extablished as follows:

$$L_t\ (20) = 1.0\ L_m\ (20/L_m\ (35)$$

or

$$L_t\ (20) = 1.0 \left[\frac{P_t\ (20)}{P_t\ (35)}\right]^{1/2}$$

where P_t (20) and P_t (35) are measured values in absolute pressure

3. The allowable operational leak rate, L_{to} (20) which shall be met prior to resumption of power operation following a test (either as measured or following repairs and retest) shall not exceed 0.75 L_t (20).

C. Corrective Action

If leak repairs are necessary to meet the allowable operational leak rate, the integrated leak rate test need not be repeated provided local leakage measurements are conducted, and the leak rate differences prior to and after repairs, when corrected to P_t and deducted from the integrated leak rate measurement, yield a leakage rate value not in excess of the allowable operation leak rate L_{to} (20).

D. Frequency

Integrated leak rate tests shall be performed within plus or minus 8 months as follows:

1. During the first refueling outage after initial criticality or 12 months, whichever is sooner.

2. Within 24 months from the date of the test in "1" above.

3. Within every 48 months from the date of the test in "2" and every 48 months thereafter.

In the event the leak rate of any test exceeds the allowable test leak rate L_t (20), the condition shall be corrected, the testing frequency shall revert to the following schedule, within plus or minus 8 months, as follows:

1. Within 12 months following the retest made (local or integrated) to correct excess leak rate.

2. Within 24 months of test 1.

3. Within 48 months of test 2.

E. Local Leak Rate Tests

1. Primary containment testable penetrations and isolation valves shall be tested at a pressure of 35 psig each refueling outage except bolted double-gasketed seals shall be tested whenever the seal is closed after being opened, and at least at each refueling outage.

2. Personnel air lock door seals will be tested at a pressure of 10 psig each refueling outage.

3. Containment components not included in 1, and 2, which required leak repairs following any integrated leakage rates in order to meet the allowable leakage rate unit L_t shall be subjected to local leak tests at a pressure of 35 psig at each refueling outage.

4. The main steam line isolation valves are to be tested at a pressure of 20 psig during each refueling outage.

F. Corrective Action

1. If the total leakage rates listed below, as adjusted to a test pressure of 20 psig, are exceeded, repairs and retests shall be performed to correct the condition.

a.	double gasketed seals	10% L_{to} (20)
b.	testable penetrations and isolation valves	30% L_{to} (20)
c.	Primary containment air purge penetrations and reactor building to torus vacuum relief valves	50% L_{to} (20)
d.	any one penetration or isolation valve	5% L_{to} (20)

G. Continuous Leak Rate Monitor

1. When the primary containment is inerted the containment shall be continuously monitored for gross leakage by review of the inerting system makeup requirements.

2. This monitoring system may be taken out of service for the purpose of maintenance or testing but shall be returned to service as soon as practical.

H. Report of Test Results

Each integrated leakage rate test shall be the subject of a summary technical report, including results of the local leakage rate tests. The report shall include analysis and interpretation of the results which demonstrate compliance in meeting the specified leakage rate limits.

I. Functional Test of Valves

1. All containment isolation valves specified in Table 3.5.2 shall be tested for automatic closure by an isolation signal during each refueling outage. The following valves are required to close in the time specified below:

Main steam line isolation valves	$\geq$ 3 sec and $\leq$ 10 sec.
Isolation condenser isolation valves	$\leq$ 60 sec.
Cleanup system isolation valves	$\leq$ 60 sec.
Cleanup auxiliary pumps system isolation valves	$\leq$ 60 sec.
Shutdown system isolation valves	$\leq$ 60 sec.

2. Each containment isolation valve shown in Table 3.5.2 shall be demonstrated operable prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator by cycling the valve through at least one complete cycle of full travel and verifying the specified isolating time. Following maintenance, repair or replacement work on the control or power circuit for the valves shown in Table 3.5.2, the affected component shall be tested to assure it will perform its intended function in the circuit.

3. During periods of sustained power operation each main steamline isolation valve shall be exercised in accordance with the following schedule.

   a. Daily tests - Exercise valve (one at a time) to approximately 95% open position with reactor at operation power level.

   b. Quarterly tests - Trip valve (one at a time) and check full closure time, with reactor power not greater than 50% of rated power.

4. Reactor Building to Suppression Chamber Vacuum Breakers

   a. The reactor building to suppression chamber vacuum breakers and associated instrumentation, including set point, shall be checked for proper operation every three months.

   b. During each refueling outage each vacuum breaker shall be tested to determine that the force required to open the vacuum breaker from closed to fully open does not exceed the force specified in Specification 3.5.A.3.a. The air-operated vacuum breaker instrumentation shall be calibrated during each refueling outage.

5. Pressure Suppression Chamber - Drywell Vacuum Breakers

a. Periodic Operability Tests

Once each month and following any release of energy which would tend to increase pressure to the suppression chamber, each operable suppression chamber - drywell vacuum breaker shall be exercised. Operation of position switches, indicators and alarms shall be verified monthly by operation of each operable vacuum breaker.

b. Refueling Outage Tests

(1) All suppression changer - drywell vacuum breakers shall be tested to determine the force required to open each valve from fully closed to fully open.

(2) The suppression chamber - drywell vacuum breaker position indication and alarm systems shall be calibrated and functionally tested.

(3) At least four of the suppression chamber - drywell vacuum breakers shall be inspected. If deficiencies are found, all vacuum breakers shall be inspected and deficiencies corrected such that Specification 3.5.A.4.a can be met.

(4) A drywell to suppression chamber leak rate test shall demonstrate that with an initial differential pressure of not less than 1.0 psi, the differential pressure decay rate shall not exceed the equivalent of air flow through a 2-inch orifice.

J. Reactor Building

1. Secondary containment capability tests shall be conducted after isolating the reactor building and placing either Standby Gas Treatment System filter train in operation.

2. The tests shall be performed at least once per operating cycle and shall demonstrate the capability to maintain a 1/4 inch of water vacuum under calm wind conditions with a Standby Gas Treatment System Filter train flow rate of not more than 4000 cfm.

3. A secondary containment capability test shall be conducted at each refueling outage prior to refueling.

4. The results of the secondary containment capability tests shall be in the subject of a summary technical report which can be included in the reports specified in Section 6.

K. Standby Gas Treatment System

1. The capability of each Standby Gas Treatment System circuit shall be demonstrated by:

a. At least once per 18 months, after every 720 hours of operation, and following significant painting, fire, or chemical release in the reactor building during operation of the Standby Gas Treatment System by verifying that:

(1) The charcoal absorbers remove $\geq$99% of a halogenated hydrocarbon refigerant test gas and the HEPA filters remove $\geq$99% of the DOP in a cold DOP test when tested in accordance with ANSI N510-1975.

(2) Results of laboratory carbon sample analysis show $\geq$90% radioactive methyl iodine removal efficiency when tested in accordance with ASTM D 3803-79 (30°C, 95% relative humidity).

b. At least once per 18 months by demonstrating:

(1) That the pressure drop across a HEPA filter is equal to or less than the maximum allowable pressure drop indicated in Figure 4.5.1.

(2) The inlet heater is capable of at least 10.9 KW input.

(3) Operation with a total flow within 10% of design flow.

c. At least once per 30 days on a STAGGERED TEST BASIS by operating each circuit for a minimum of 10 hours.

d. Anytime the HEPA filter bank or the charcoal adsorbers have been partially or completely replaced, the test for 4.5.K.1.a will be performed prior to returning the system to OPERABLE STATUS.

e. Automatic initiation of each circuit every 18 months.

L. Deleted.

"M. Inerting Surveillance

When an inert atmosphere is required in the primary containment the oxygen concentration in the primary containment shall be checked at least weekly.

"N. Drywell Coating Surveillance

Carbon steel test panels coated with Firebar D shall be placed inside the drywell near the reactor core midplane level. They shall be removed for visual observation and weight loss measurements during the first, second, fourth and eighth refueling outages."

O. Instrument Line Flow Check Valves Surveillance

The capability of each instrument line flow check valve to isolate shall be tested at least once in every period between refueling outages. Each time an instrument line is returned to service after any condition which could have produced a pressure or flow disturbance in that line, the open position of the flow check valve in that line shall be verified. Such conditions include:

Leakage at instrument fittings and valves
Venting an instrument or instrument line
Isolating an instrument
Flushing or draining an instrument

P. Suppression Chamber Surveillance

1. At least once per day the suppression chamber water level and temperature and pressure suppression system pressure shall be checked.

2. A visual inspection of the suppression chamber interior, including water line regions, shall be made at each major refueling outage.

3. Whenever heat from relief valve operation is being added to the suppression pool, the pool temperature shall be continually monitored and also observed until the heat addition is terminated.

4. Whenever operation of a relief valve is indicated and the suppression pool temperature reaches 160°F or above while the reactor primary coolant system pressure is greater than 180 psig, an external visual examination of the suppression chamber shall be made before resuming normal power operation.

Q. Shock Suppressors (Snubbers)

1. Each snubber shall be demonstrated operable by performance of the following inspection program:

a. Visual Inspections

All snubbers shall be visually inspected in accordance with the following schedule:

No. Inoperable Snubbers Per Inspection Period	Subsequent Visual Inspection Period*
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3, 4	124 months ± 25%
5, 6, 7	62 days ± 25%
8 or more	31 days ± 25%

* The provisions of Technical Specification 1.24 are not applicable.

The required inspection interval shall not be lengthened more than one step at a time. The snubbers may be categorized into two groups: those accessible and those inaccessible during reactor operation. Each group may be inspected independently in accordance with the above schedule.

b. Visual Inspection Acceptance Criteria

Visual inspections shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are secure, and (3) in those locations where snubber movement can be manual induced without disconnecting the snubber, that the snubber has freedom of movement and is not frozen up. Snubbers which appear inoperable as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, providing that the affected snubber is functionally tested in the as found condition and determined operable per Specification 4.5.Q.d or 4.5.Q.e as applicable and that the cause for the rejection has been clearly established and remedied for that particular snubber.

c. Functional Tests

At least once each refueling cycle, a representative sample (10% of the total of each type of snubber in use in the plant) shall be functionally tested either in place or in a bench test. For each snubber that

does not meet the functional test acceptance criteria of Specification 4.5.Q.d or 4.5.Q.e, an additional 10% of that type of snubber shall be functionally tested. As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, mechanical or hydraulic.

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

1. The first snubber away from each reactor vessel nozzle.

2. Snubbers within 5 feet of heavy equipment (valve, pump, motor, etc.).

3. Snubbers within 10 feet of the discharge from a safety relief valve.

In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed (if it is repaired and installed in another position) and the replacement snubber shall be retested. The results from testing of these snubbers are not included for determining additional sampling requirements.

For any snubber that fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated. If caused by manufacturer or design deficiency, actions shall be taken to ensure that all snubbers of the same design are not subject to the same defect.

d. Hydraulic Snubbers Functional Test Acceptance Criteria

The hydraulic snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber bleed, or release rate, where required, is within the specified range in compression or tension. For snubbers specifically required to not displace under continous load, the ability of the snubber to withstand load without displacement shall be verified.

e. Mechanical Snubbers Functional Test Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiated free movement of the snubber rod in either tension or compression is less than the specified maximum drag force.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

3. Snubber release rate, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

f. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained as required by Specification 6.10.2.1.

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This reevaluation, replacement or reconditioning shall be indicated in the records. Service life shall not at any time affect reactor operations.

Basis: 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 38 psig which would rapidly reduce to 20 psig within 100 seconds following the pipe break. The total time the drywell pressure would be above 35 psig is calculated to be about 7 seconds. Following the pipe break, absorption chamber pressure rises to 20 psig within 8 seconds, equalizes with drywell pressure at 25 psig within 60 seconds and thereafter rapidly decays with the drywell pressure decay.(1)

The design pressures of the drywell and absorption chamber are 62 psig and 35 psig, respectively.(2) The design leak rate is 0.5%/day at a pressure of 35 psig. As pointed out above, the pressure response of the drywell and absorption chamber following an accident would be the same after about 60 seconds. Based on the calculated primary containment pressure response discussed above and the absorption chamber design pressure, primary containment preoperational test pressures were chosen. Also, based on the primary containment pressure response and the fact that the drywell and absorption chamber function as a unit, the primary containment will be tested as a unit rather than testing the individual components separately.

The design basis loss-of-coolant accident was evaluated at the primary containment maximum allowable accident leak rate of 1.0%/day at 35 psig. The analysis showed that with this leak rate and a standby gas treatment system filter efficiency of 90 percent for halogens, 95% for particulates, and assuming the fission product release fractions stated in TID-14844, the maximum total whole body passing cloud dose is about 10 rem and the maximum total thyroid dose is about 139 rem at the site boundary considering fumigation conditions over an exposure duration of two hours. The resultant doses that would occur for the duration of the accident at the low population distance of 2 miles are lower than those stated due to the variability of meteorological conditions that would be expected to occur over a 30-day period. Thus, the doses reported are the maximum that would be expected in the unlikely event of a design basis loss-of-coolant accident. These doses are also based on the assumption of no holdup in the secondary containment resulting in a direct release of fission product from the primary containment through the filters and stack to the environs. Therefore, the specified primary containment leak rate and filter efficiency are conservative and provide margin between expected offsite doses and 10 CFR 100 guideline limits.

Although the dose calculations suggest that the allowable test leak rate could be allowed to increase to about 2.0%/day before the guideline thyroid dose limit given in 10 CFR 100 would be exceeded, establishing the limit of 1.0%/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 operational limit is derived by multiplying the allowable test leak rate 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 AEC guide for developing leak rate testing and surveillance of reactor containment vessels.(4) 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 double gasketed penetration (primary containment head equipment hatches and the absorption chamber access hatch) is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. The test pressure of 35 psig is consistent with the accident analyses and the maximum preoperational leak rate test pressure. If the leakage rates of the double gasketed seal penetrations, testable penetration isolation valves, containment air purge inlets and outlets and the vacuum relief valves are at the maximum specified, they will total 90 percent of the allowed leak rate.(5) Hence 10% margin is left for leakage through walls and untested components.

Monitoring the nitrogen makeup requirements of the inerting system provides a method of observing leak rate trends and would detect gross leaks in a very short time. This equipment must be periodically removed from service for test and maintenance, but this out-of-service time will be kept to a practical minimum.

The containment integrity isolation valves are provided to maintain containment integrity following the design basis loss-of-coolant accident. The closure times of the isolation valves on the containment are not critical because it is on the order of minutes before significant fission product release to the containment atmosphere for the design basis loss of coolant. These valves are highly reliable, see infrequent service and most of them are normally in the closed position. Therefore, a test during each refueling outage is sufficient.(6)

Large lines connecting to the reactor coolant system, whose failure could result in uncovering the reactor core, are supplied with automatic isolation valves (except containment cooling). The specified closure times are adequate to restrict the coolant loss from the circumferential rupture of any of these lines outside the containment to less than that for a main steam line rupture. Therefore, this isolation valve closure time is sufficient to prevent uncovering the core.(7)

Since the main steam line isolation valves are normally in the open position, more frequent testing is specified. Daily exercising the valves to about the 95% open position provides assurance of their operability and the quarterly full closure test provides assurance that the valves maintain the required closing time. The minimum time of 3 seconds is based on the transient analysis of the isolation valve closure that shows the pressure peak 76 psig below the lowest safety valve setting. The maximum time of 10 seconds provides a 0.5 second margin to the 10.5 seconds that is assumed for the main steam line break dose calculations.

Surveillance of the suppression chamber-reactor building vacuum breakers consists of operability checks and leakage tests (conducted as part of the containment leak - tightness tests). These vacuum breakers are normally in the closed position and open only during tests or an accident condition. As a result, a testing frequency of three months for operability is considered justified for this equipment. Inspections and calibrations are performed during the refueling outages, this frequency being based on equipment quality, experience, and engineering judgment.

The fourteen suppression chamber-drywell vacuum relief valves are designed to open to the full open position (the position that curtain area is equivalent to valve bore) with a force equivalent to a 0.5 psi differential acting on the suppression chamber face of the valve disk. This opening specification assures that the design limit of 2.0 psid between the drywell and external environment is not exceeded. Once each refueling outage each valve is tested to assure that it will open fully in response to a force less than that specified. Also it is inspected to assure that it closes freely and operates properly.

The containment design has been examined to establish the allowable bypass area between the drywell and suppression chamber as 10.5 in.^{2} (expressed as vacuum breaker open area). This is equivalent to one vacuum breaker disk off its seat 0.371 inch; this length corresponds to an angular displacement of 1.25°. A conservative allowance of 0.10 inch has been selected as the maximum permissible valve opening. Valve closure within this limit may be determined by light indication from two independent position detection and indication systems. Either system provides a control room alarm for a non-seated valve.

At the end of each refueling cycle, a leak rate test shall be performed to verify that significant leakage flow paths do not exist between the drywell and suppression chanber. The drywell pressure will be increased by at least 1 psi with respect to the suppression chamber pressure. The 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. If the drywell pressure can be increased by 1 psi over the suppression chamber the rate of change of the suppression chamber pressure must not exceed a rate equivalent to the rate of air flow from the drywell

to the suppression chamber through a 2-inch orifice. In the event the rate of change of pressure exceeds this value, then the source of leakage will be identified and eliminated before power operation is resumed.

The drywell-suppression chamber vacuum breakers are exercised monthly and immediately following termination of discharge of steam into the suppression chamber. This monitoring of valve operability is intended to assure that valve operability and position indication system performance does not degrade between refueling inspections. When a vacuum breaker valve is exercised through an opening-closing cycle, the position indicating lights are designed to function as follows:

Full Closed	2 Green - On
(Closed to 0.10" open)	2 Red - Off
Open 0.10"	2 Green - Off
(0.10" open to full open)	2 Red - On

During each refueling outage, four suppression chamber-drywell vacuum breakers will be inspected to assure components have not deteriorated. Since valve internals are designed for a 40-year lifetime, an inspection program which cycles through all valves in about one-tenth of the design lifetime is extemely conservative. The alarm systems for the vacuum breakers will be calibrated during each refueling outage. This frequency is based on experience and engineering judgement.

Initiating reactor building isolation and operation of the standby gas treatment system to maintain a 1/4 inch of water vacuum, tests the operation of the reactor building isolation valves, leakage tightness of the reactor building and performance of the standby gas treatment system. Checking the initiating sensors and associated trip channels demonstrates the capability for automatic actuation. Performing the reactor building in leakage test prior to refueling demonstrates secondary containment capability prior to extensive fuel handling operations associated with the outage. Verifying the efficiency and operation of charcoal filters once per 18 months gives sufficient confidence of standby gas treatment system performance capability. A charcoal filter efficiency of 99% for halogen removal is adequate.

The in-place testing of charcoal filters is performed using Freon-112* which is injected into the system upstream of the charcoal filters. Measurement of the Freon concentration upstream and downstream of the charcoal filters is made using a gas chromatograph. The ratio of the inlet and outlet concentrations gives an overall indication of the leak tightness of the system. Although this is basically a leak test, since the filters have charcoal of known efficiency and holding capacity for elemental iodine and/or methyl iodide, the test also gives an indication of the relative efficiency of the installed system. The test procedure is an adaptation of test procedures

*Trade name of E. I. DuPont de Nemours & Company

developed at the Savannah River Laboratory which were described in the Ninth AEC Air Cleaning Conference.*

High efficiency particulate filters are installed before and after the charcoal filters to minimize potential release of particulates to the environment and to prevent clogging of the iodine filters. An efficiency of 99% is adequate to retain particulates that may be released to the reactor building following an accident. This will be demonstrated by testing with DOP at testing medium.

If laboratory tests for the adsorber material in one circuit of the Standby Gas Treatment System are unacceptable, all adsorber material in that circuit shall be replaced with adsorbent qualified according to Regulatory Guide 1.52. Any HEPA filters found defective shall be replaced with those qualified with Regulatory Position C.3.d of Regulatory Guide 1.52.

The snubber 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. Visual inspections performed before an inspection 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.

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 represents an adequate sample for such tests. Observed failures of these samples require testing of additional units.

After the containment oxygen concentration has been reduced to meet the specification initially, the containment atmosphere is maintained above atmospheric pressure by the primary containment inerting system. This system supplies nitrogen makeup to the containment so that the very slight leakage from the containment is replaced by nitrogen, further reducing the oxygen concentration. In addition, the oxygen concentration is continuously recorded and high oxygen concentration is annunciated. Therefore, a weekly check of oxygen concentration is adequate. This system also provides capability for determining if there is gross leakage from the containment.

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*D. R. Muhabier, "In Place Nondestructive Leak Test for Iodine Absorbers," Proceedings of the Ninth AEC Air Cleaning Conference, USAEC Report CONF-660904, 1966.

The drywell exterior was coated with Firebar D prior to concrete pouring during construction. The Firebar D separated the drywell steel plate from the concrete. After installation, the drywell liner was heated and expanded to compress the Firebar D to supply a gap between the steel drywell and the concrete. The gap prevents contact of the drywell wall with the concrete which might cause excessive local stresses during drywell expansion in a loss-of-coolant accident. The surveillance program is being conducted to demonstrate that the Firebar D will maintain its integrity and not deteriorate throughout plant life. The surveillance frequency is adequate to detect any deterioration tendency of the material.[8]

The operability of the instrument line flow check valves are demonstrated to assure isolation capability for excess flow and to assure the operability of the instrument sensor when required.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be continually monitored and also observed during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken. The requirement for an external visual examination following any event where potentially high loadings could occur provides assurance that no significant damage was encountered. Particular attention should be focused on structural discontinuities in the vicinity of the relief valve discharge since these are expected to be the points of highest stress.

References

(1) Licensing Application, Amendment 32, Question 3
(2) FDSAR, Volume I, Section V-1.1
(3) Deleted
(4) Technical Safety Guide, "Reactor Containment Leakage Testing and Surveillance Requirements," USAEC Division of Safety Standards, Revised Draft, December 15, 1966.
(5) FDSAR, Volume I, Sections V-1.5 and V-1.6
(6) FDSAR, Volume I, Sections V-1.6 and XIII-3.4
(7) FDSAR, Volume I, Section XIII-2
(8) Licensing Application, Amendment 11, Question III-18

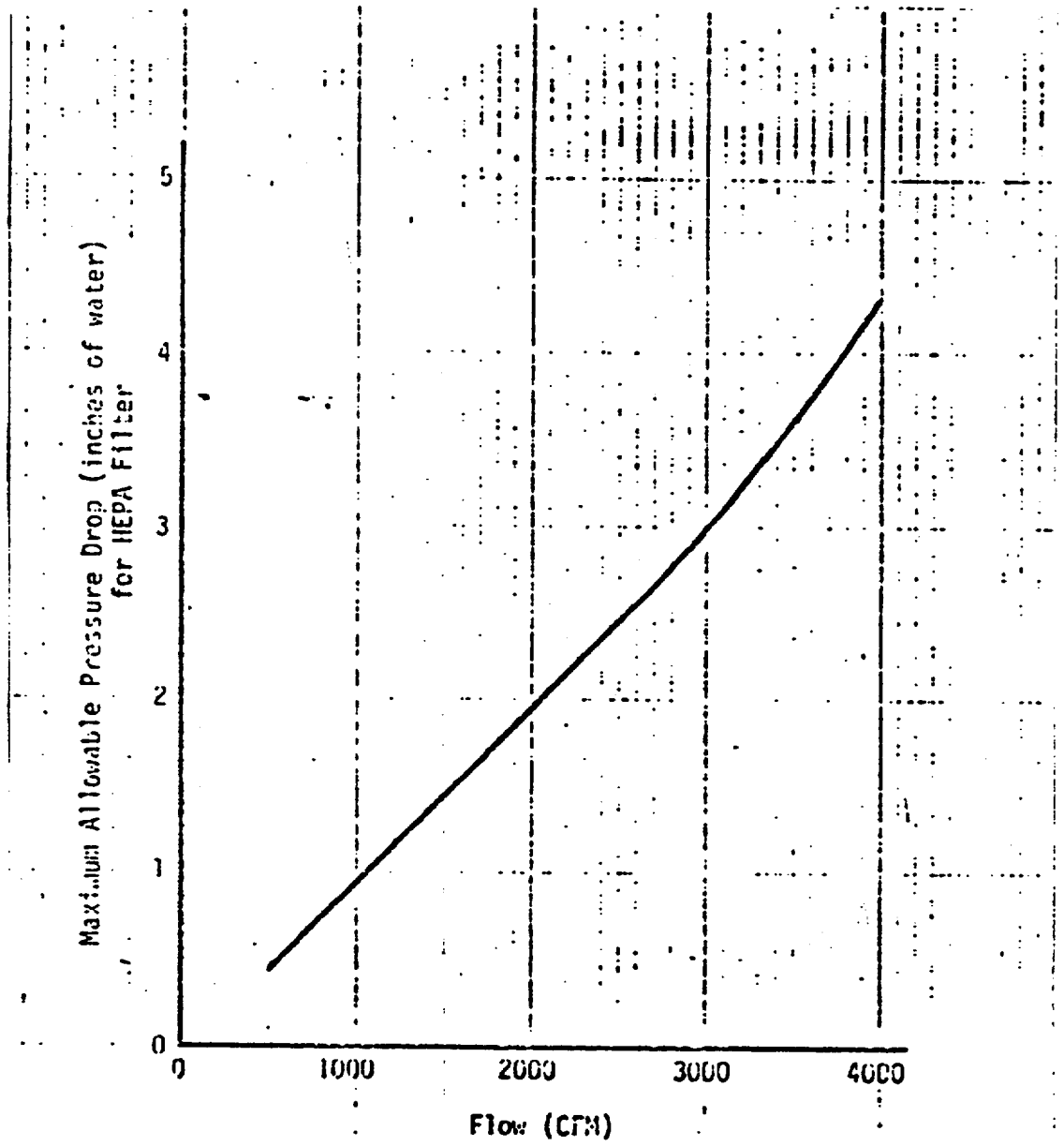


Figure 4.5.1

MAXIMUM ALLOWABLE PRESSURE DROP
FOR HEPA FILTERS

4.6 RADIOACTIVE EFFLUENTS

Applicability: Applies to monitoring of the gaseous and liquid radioactive effluents of the facility.

Objective: To verify that discharge of radioactive effluents to the environment is kept to a practical minimum and, in any event, within the limits of 10 CFR 20.

Specification:

A. The stack gas and radwaste liquid effluent radiation monitoring channels shall be checked daily, tested monthly, and calibrated every 3 months.

"B. (1) Stack Release

(a) Station records of gross stack release rate of gaseous activity and meteorological conditions shall be maintained on an hourly basis to assure that the specified rates are not exceeded, to provide data for calculating offsite dose and to yield information concerning general integrity of the fuel cladding.

(b) Within one month after issuance of these specifications and within one month following refuelings, an isotopic analysis will be made of a gaseous activity release sample which identifies at least 90 percent of the total activity. From this sample, a ratio of long-lived (> 8 day half life) and short-lived activity will be established.

(c) Samples of off-gas will be taken at least every 96 hours and gross ratio of long-lived (> 8 day half life) and short-lived activity determined.

(d) An isotopic analysis of off-gas will be performed monthly unless the ratio determined in (c) differs from the ratio established by the previous isotopic analysis by more than 20 percent. If this occurs, a new isotopic analysis shall be performed.

(e) Gaseous release of tritium shall be measured at least quarterly.

(f) Station records of stack release of iodines and particulates with half lives greater than eight days shall be maintained on the basis of all filter cartridges counted.

(g) These cartridges shall be analyzed weekly for gross alpha, beta and gamma activity, Ba-140, La-140 and I-131 when the iodine or particulate release rate is

less than 4 percent of the maximum release rate given in Specification 3.6.A(2), otherwise the cartridges shall be removed for analysis twice a week.

(h) When the gross gaseous release rate exceeds 1 percent of the maximum release rate given in Specification 3.6.A(1) and the average daily gross activity release rate increased by 50 percent over the previous full operating day, the cartridges shall be analyzed to determine the release rate increase for iodines and particulates.

(i) An isotopic analysis of iodines and particulate radionuclides shall be performed at least quarterly.

(2) Liquid Release

(a) Station records shall be maintained of the radioactive concentration 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.

(b) A weekly proportional composite* of samples of each batch discharged during the week shall be analyzed for gross alpha, beta and gamma activity, Ba-140, La-140, I-131, dissolved gases such as Xe-133 and other shorter lived radionuclides (half lives of 15 days or less) which are associated with routes of potential exposure to man.

(c) A monthly proportional composite of samples of each batch discharged during the month shall be analyzed for gross alpha, beta and gamma activity, tritium and the principal gamma emitting fission and activation products in the sample, including longer lived radionuclides associated with routes of potential exposure to man. The analysis should account for at least 90 percent of the total activity, exclusive of tritium and dissolved gases, and should include at least Cs-137, Cs-134, Co-60, Co-58, Cr-51, Mn-54 and Zn-65.

(d) A quarterly proportional composite shall be analyzed for Sr-90.

(e) Each batch of liquid effluent released shall be analyzed for gross alpha, beta and gamma activity and the results recorded. Should there be any unexplained significant change in gross alpha, beta or gamma activity from pervious isotopic analyses, a new isotopic analysis shall be performed.

*A proportional composite is one in which the quantity of liquid added to the composite is proportioned to the quantity of liquid in the batch that was released.

(f) If a batch is to be released on an indentified radionuclide basis, the analysis shall also include a gamma scan. If gamma peaks different from those determined by previous isotopic analyses are found or if the mixture concentration is greater than 10 percent of the mixture MPC, a new isotopic analysis shall be performed and recorded.

(3) Environmental Program

The environmental program described in Section B.II.6 of Amendment 65 to the Application for Reactor Operating License shall be conducted. The sampling frequencies specified in Table B-II-1 of Amendment 65 shall be adhered to as closely as conditions permit."

C. A sample of reactor coolant shall be analyzed at least every 72 hours to determine total radioactive iodine content.

D. Liquids contained in the waste sample tanks, floor drain sample tanks, and the waste surge shall be sampled and analyzed at least every 72 hours to determine the total activity in curies unless a tank has been valved out of service after determining its radioactive content.

E. The operability of all equipment installed for the treatment of liquid wastes shall be verified at least once per quarter.

F. The calculations specified in section 3.6.F shall be performed at least once per month.

Basis: The check, test, and calibration requirements are specified to detect possible equipment failure and to show that maximum permissible release rates are not exceeded. The monitors(1) operate continuously and by virtue of normal plant operation, the operators daily observe that the instruments are performing. Failure of an instrument is evident, because of upscale, downscale, or loss of voltage alarms. The monitor trip points may be readily checked by a built-in push-button operated circuit. A portable test source may be affixed to the detector to re-establish calibration. Experience with instrument drift and failure modes indicates that the specified test frequency is adequate and consistent with other instrumentation.

Continuous monitoring of the gaseous and collection of the particulate stack effluents provides the means for determining that the limits of Specification 3.6.A are not exceeded and for recording the actual levels of radioactivity that are being released from the stack. The frequencies of filter and cartridge analyses and isotopic analyses are specified to assure proper identification of the isotopes being released. The sampling and analysis of each batch of the radioactive liquid effluent provide the means for determining the release rate to the discharge canal to assure the limits of Specification 3.6.B are not exceeded. The isotopic analyses of the weekly and monthly

proportional composites of liquid waste samples provide the data for recording and reporting the average concentrations of radioactivity and total radioactivity released from the discharge canal. These isotopic analyses shall also provide the normal means for calibrating gross alpha, beta and gamma analyses that are used to determine the concentration of batch for discharge on an unidentified basis. More frequent isotopic analyses shall be required in conformance with 4.6.B.2.(e) & (f) to assure that the calibration of gross counts has not been altered by a change in the mixture of radioisotopes.

The release of effluents on an identified radionuclide basis shall be based on the isotopic analysis of a typical waste batch provided that the gross counting analysis and the gamma scan indicate no significant change in the mixture constituents or the resultant mixture after dilution does not exceed 10 percent of the mixture MPC. If either of these two conditions occur, an isotopic analysis of the batch to be discharged shall be performed.

A minimum dilution factor for the isotopic mixture shall be determined using the following formula:

$$\text{Minimum D.F.} = \frac{C_1}{MPC_1} + \frac{C_2}{MPC_2} + \ldots + \frac{C_n}{MPC_n}$$

Where: C_1 = concentration of isotope 1, etc.

MPC_1 = MPC of isotope 1 from Appendix B, Table II, Column 2, 10 CFR 20, etc.

C_n will normally be the concentration of unidentified activity remaining after identification of isotopes.

This dilution factor can be expressed as a MPC for the isotopic mixture thus:

$$\text{Mixture MPC} = \frac{\text{gross concentration}}{\text{Minimum D.F.}}$$

This mixture MPC shall be used to determine the appropriate discharge rates and dilution for waste batches but can only be used for the particular mixture as determined above."

Sampling of the radioactive liquids contained in the radwaste tanks located outside the radwaste facility will be used to assure that the limit of Specification 3.6.C is not exceeded. Due to normal decay, a tank needs to be sampled only once, as long as no additional radioactive liquids have been added. The liquid level in all these tanks is recorded and high level annunciated. In addition, floor drain sample tanks and waste sample tanks are batch-emptied so that as one tank is being discharged the other may be filled. Therefore, both tanks of a type could not normally be expected to be filled at the same time. The waste surge tank is used as backup storage capacity during maintenance on other tanks or to accommodate other unusual conditions.

The reactor water sample will be used to assure that the limit of Specification 3.6.D is not exceeded. The total radioactive iodine activity would not be expected to change rapidly over a period of several days. In addition, the trend of the stack off-gas release rate, which is continuously monitored, is a good indicator of the trend of the iodine activity in the reactor coolant.

Reference

(1) FDSAR, Volume I, Sections VII-6-2-3 and VII-6-2-5

4.7 AUXILIARY ELECTRICAL POWER

Applicability: Applies to surveillance requirements of the auxiliary electrical supply.

Objective: To verify the availability of the auxiliary electrical supply.

Specification: A. Diesel Generator

1. Each diesel generator shall be started and loaded to not less than 20% rated power every two weeks.

2. The two diesel generators shall be automatically actuated and functionally tested during each refueling outage. This shall include testing of the diesel generator load sequence timers listed in Table 3.1.1.

3. Each diesel generator shall be given a thorough inspection at least once per 18 months during shutdown.

4. The diesel generators' fuel supply shall be checked following the above tests.

5. The diesel generators' starting batteries shall be tested and monitored the same as the station batteries, Specification 4.7.b.

B. Station Batteries

1. Weekly surveillance will be performd to verify the following:

   a. The active metallic surface of the plates shall be fully covered with electrolyte in all batteries,

   b. The designated pilot cell voltage is greater than or equal to 2.0 volts and

   c. The overall battery voltage is greater than or equal to 120 volts (Diesel battery; 112 volts).

   d. The pilot cell specific gravity, corrected to 77°F, is greater than or equal to 1.190.

2. Quarterly Surveillance will be performed to verify the following:

   a. The active metallic surface of the plates shall be fully covered with electrolyte in all batteries,

   b. The voltage of each connected cell is greater than or equal to 2.0 volts under float charge and

c. The specific gravity, for each cell, is greater than or equal to 1.190 when corrected to 77°F. The electrolyte temperature of every fifth cell (Diesel; every fourth cell) shall be recorded for surveillance review.

3. At least once per 18 months during shutdown, the following tests will be performed to verify battery capacity.

   a. Battery capacity shall be demonstrated to be at least 80% of the manufacturers' rating when subjected to a battery capacity discharge test.

   b. Battery low voltage annunicators are verified to pick up at 115 volts ± 1 volt and to reset at 125 volts ± 1 volt (Diesel; 112 volts ± 1 volt).

Basis: The biweekly tests of the diesel generators are primarily to check for failures and deterioration in the system since last use. The manufacturer has recommended the two week test interval, based on experience with many of their engines. One factor in determining this test interval (besides checking whether or not the engine starts and runs) is that the lubricating oil should be circulated through the engine approximately every two weeks. The diesels should be loaded to at least 20% of rated power until engine and generator temperatures have stabilized (about one hour). The minimum 20% load will prevent soot formation in the cylinders and injection nozzles. Operation up to an equilibrium temperature ensures that there is no over-heat problem. The tests also provide an engine and generator operating history to be compared with subsequent engine-generator test data to identify and 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 assume load in less than 20 seconds and testing of the diesel generator load sequence timers which provide protection from a possible diesel generator overload during LOCA conditions. Thorough inspections will detect any signs of wear long before failure.

The manufacturer's instructions for battery care and maintenance with regard to the floating charge, the equalizing charge, and the addition of water will be followed. In addition, written records will be maintained of the battery performance. Station batteries will deteriorate with time, but precipitous failure is unlikely. The station surveillance procedures follow the recommended maintenance and testing practices of IEEE STD. 450 which have demonstrated, thorough experience, the ability to provide positive indications of cell deterioration tendencies long before such tendencies cause cell irregularity or improper cell performance.

4.8 ISOLATION CONDENSER

Applicability: Applies to periodic testing requirements for the isolation condenser system.

Objective: To verify the operability of the isolation condenser system.

Specification:

A. Surveillance of each isolation condenser loop shall be as follows:

Item	Frequency
1. Operability of motor operated isolation valves and condensate makeup valves.	Once/month
2. Automatic actuation and functional test.	Each refueling outage or following major repair.
3. Shell side water volume check.	Once/day
4. Isolation valve (steam side)	
a. Visual inspection	Each refueling outage
b. External leakage check	Each primary system leak test
c. Area temperature check	Once/shift

Basis: Motor operated valves on the isolation condenser steam and condensate lines and on the condensate makeup line that are normally on standby should be exercised periodically to make sure that they are free to operate. The valves will be stroked full length every time they are tested to verify proper functional performance. This frequency of testing is consistent with instrumentation tests discussed in Specification 4.1. Engineering judgment based on experience and availability analyses of the type presented in Appendix L of the FDSAR indicates that testing these components once a month provides assurance of availability of the system. Also, at this frequency of testing, wearout should not be a problem throughout the life of the plant.

The automatic actuation and functional test will demonstrate the automatic opening of the condensate return line valves and the automatic closing of the isolation valves on the vent lines to the main steam lines. Automatic closure of the isolation condenser steam and condensate lines on actuation of the condenser pipe break detectors will also be verified by the test. It is during a major maintenance or repair that a system's design intent may be violated accidentally. This makes the functional test necessary after every major repair operation.

By virtue of normal plant operation the operators daily observe the water level in the isolation condensers. In addition, isolation condenser shell side water level sensors provide control room annunciation of condenser high or low water level.

Each refueling outage the insulation will be removed from the steam side isolation valve and the external valve bodies will be inspected for signs of deterioration. Additionally, special attention is specified for these valves during primary system leakage tests and the temperature in the area of these valves is checked once each shift for temperature increases that would indicate valve leakage. The special attention given these valves in the design and during their construction[1] along with the indicated surveillance is judged to be adequate to assure that these valves will maintain their integrity when they are required for isolation of the primary containment.

Reference

(1) Licensing Application, Amendment 32, Question 5

4.9 REFUELING

Applicability: Applies to the periodic testing of those interlocks and instruments used during refueling.

Objective: To verify the operability of instrumentation and interlocks in use during refueling.

Specification:

A. The refueling interlocks shall be tested prior to any fuel handling with the head off the reactor vessel, at weekly intervals thereafter until no longer required and following any repair work associated with the interlocks.

B. Prior to beginning any core alterations, the source range monitors (SRMs) shall be calibrated. Thereafter, the SRM's will be checked daily, tested monthly and calibrated every 3 months until no longer required.

C. Within four (4) hours prior to the start of control rod removal pursuant to Specification 3.9.E verify:

1. That the reactor mode switch is locked in the refuel position and that the one rod out refueling interlock is operable.

2. That two (2) SRM channels, one in the core quadrant where the control rod is being removed and one in an adjacent quadrant, are operable and inserted to the normal operation level.

D. Verify within four (4) hours prior to the start of control rod removal pursuant to Specification 3.9.F and at least once per 24 hours thereafter, until replacement of all control rods or rod drive mechanisms and all control rods are fully inserted that:

1. the reactor mode switch is locked in the refuel position and the one rod out refueling interlock is operable.

2. Two (2) SRM channels, one in the core quadrant where a control rod is being removed and one in an adjacent quadrant, are operable and fully inserted.

3. All control rods not removed are fully inserted with the exception of one rod which may be partially withdrawn not more than two notches to perform refueling interlock surveillance.

4. The four fuel assemblies surrounding each control rod or rod drive mechanism being removed or maintained at the same time are removed from the core cell.

E. Verify prior to the start of removal of control rods pursuant to Specification 3.9.F that Specification 3.9.F.5 will be met.

F. Following replacement of a control rod or rod drive mechanism removed in accordance with Specification 3.9.F, prior to inserting fuel in the control cell, verify that the bypassed refueling interlocks associated with that rod have been restored and that the control rod is fully inserted.

Basis: The refueling interlocks[1] are required only when fuel is being handled and the head is off the reactor vessel. A test of these interlocks prior to the time when they are needed is sufficient to ensure that the interlocks are operable. The testing frequency for the refueling interlocks is based upon engineering judgment and the fact that the refueling interlocks are a backup for refueling procedures.

The SRM's[2] provide neutron monitoring capability during core alterations. A calibration using external testing equipment to calibrate the signal conditioning equipment prior to use is sufficient to ensure operability. The frequencies of testing, using internally generated test signals, and recalibration, if the SRM's are required for an extended period of time, are in agreement with other instruments of this type which are presented in Specification 4.1.

The surveillance requirements for control rod removal assure that the requirements of Specification 3.9 are met prior to initiating control rod removal and at appropriate intervals thereafter.

References:
(1) FDSAR, Volume I, Section VII-7-2.5
(2) FDSAR, Volume I, Sections VII-4.2.2 and VII-4-5.1

4.10 ECCS RELATED CORE LIMITS

Applicability: Applies to the periodic measurement during power operation of core parameters related to ECCS performance.

Objective: To assure that the limits of Section 3.10 are not being violated.

Specification:

A. Average Planar LHGR.

The APLHGR for each type of fuel as a function of average planar exposure shall be checked daily during reactor operation at greater than or equal to 25% rated thermal power.

B. Local LHGR

The LHGR as a function of core height shall be checked daily during reactor operation at greater than or equal to 25% rated thermal power.

C. Minimum Critical Power Ratio (MCPR).

MCPR shall be checked daily during reactor operation at greater than or equal to 25% rated thermal power.

Bases:

The LHGR shall be checked daily to determine whether 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.

The minimum critical power ratio (MCPR) is unlikely to change significantly during steady state power operation so that 24 hours is an acceptable frequency for surveillance. In the event of a single pump trip, 24 hours surveillance interval remains acceptable because the accompanying power reduction is much larger than the change in MAPLHGR limits for four loop operation at the corresponding lower steady state power level as compared to five loop operation. The 24 hours frequency is also acceptable for the APRM status check since neutron monitoring system failures are infrequent and a downscale failure of either an APRM or LPRM initiates a control rod withdrawal block, thus precluding the possibility of a control rod withdrawal error.

At core power levels less than or equal to 25% rated thermal power the reactor will be operating at or above the minimum recirculation pump speed. For all designated control rod patterns which may be employed at this point, operating plant experience and thermal hydraulic analysis indicate that the resulting APLHGR, LHGR and MCPR values all have considerable margin to the limits of Specification 3.10. Consequently, monitoring of these quantities below 25% of the rated thermal power is not required.

4.11 Sealed Source Contamination

Applicability: Applies to each licensed sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting materials or 5 microcuries of alpha emitting material.

Objective: To detect and prevent contamination from sealed source leakage.

Specification:

A. Radioactive sources shall be tested for contamination. The test shall be capable of detecting the presence of 0.005 microcuries of radioactive material on the test sample. If the test reveals the presence of 0.005 microcuries or more of removable contamination, it shall immediately be withdrawn from use, decontaminated, and repaired, or be disposed of in accordance with Commission regulations.

B. Tests for contamination shall be performed by the licensee or by other persons specifically authorized by the Commission or an agreement state as follows:

1. Each sealed source, except startup sources previously subjected 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 contamination at intervals not to exceed six months.

2. 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 prior to any use or transfer to another user unless they have been tested within six months prior to the date of use or transfer. In the absence of a certificate 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.

3. Startup sources shall be tested prior to and following any repair or modification and within 31 days before being subjected to core flux.

Bases:

Ingestion or inhalation of source material may give rise to total body or organ irradiation. This specification assures that leakage from radioactive material sources does not exceed allowable limits.

4.12 Fire Protection

Applicability: Applies to the surveillance requirements of the Fire Protection Systems in safety related areas/zones.

Objective: To specify the minimum frequency and type of surveillance to be applied to fire protection equipment and instrumentation.

Specification:

A. Fire Detection Instrumentation

1. Each of the instruments in Table 3.12.1 shall be demonstrated operable by a channel function test at least once per 6 months.

2. The NFPA Code 72D(1977) Class A supervised circuits supervision associated with the detector alarms of each of the above required fire detection instruments shall be demonstrated operable at least once per 6 months.

B. Fire Suppression Water System

1. The Fire Suppression Water System shall be demonstrated operable:

a. At least once per month on a staggered test basis by starting each pump and operating it for at least (15) minutes on recirculation flow.

b. At least once per month by verifying that each valve in the flow path is in its correct position.

c. At least once per 12 months by performance of a system flush.

d. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

e. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence, and:

1. Verifying that each pump develops at least 2000 gpm at a system head of 360 feet.

2. Verifying that the pump operates for greater than or equal to 60 minutes.

3. Verifying that each high pressure pump starts sequentially to maintain the fire suppression water system pressure at 125 psig or greater.

f. At least once per 3 years by performing a flow test of the system in accordance with Chapter 5, Section 11 of the Fire Protection Handbook, 14th Edition published by the National Fire Protection Association.

2. The Fire Pump Diesel Engine shall be demonstrated operable.

   a. At least once per month by verifying the fuel storage tank contains at least 275 gallons of fuel.

   b. At least once per month by verifying that the diesel starts from ambient conditions and operates for at least 30 minutes on a circulation flow.

   c. At least once per 3 months by verifying that a fuel sample, obtained in accordance with ASTM-0270-65, from each tank is within the acceptable limits specified in Table 1 of ASTM D 975-1974 when checked for viscosity, water and sediment.

3. The Fire Pump Diesel 24 volt battery bank and associated charger shall be demonstrated operable:

   a. At least once per week by verifying that:

      1. The electrolyte level of each cell is above the plates,

      2. The pilot cell voltage is greater than or equal to 2.0 volts or 12.0 volts based on the cell configuration used.

      3. The pilot cell specific gravity, corrected to 77F, will be recorded for surveillance review,

      4. The overall battery voltage is greater than or equal to 24 volts.

   b. At least once per 3 months by verifying that:

      1. The voltage of each connected cell is greater than or equal to 2.0 volts or 12.0 volts based on the cell configuration used.

      2. The specific gravity, corrected to 77 F, of each cell will be recorded for surveillance review.

      3. The electrolyte level of each cell is above the plates.

   c. At least once per 18 months by verifying that:

      1. The batteries, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration, and

2. The battery-to-battery and terminal connections are clean, tight, free of corrosion and coated with an anticorrosion material.

C. Spray and/or Sprinkler Systems

1. The spray and/or sprinkler systems listed in Table 3.12.2 shall be demonstrated operable at least once per 18 months:

a. By performing a system functional test which includes simulated automatic actuation of the system and verifying that the automatic valves in the flow path actuate to their correct positions.

b. By inspection of the water headers to verify their integrity.

c. By inspection of each open spray nozzle to verify no blockage.

D. Hose Stations

1. Each of the hose stations listed in Table 3.12.3 shall be verified operable:

a. At least once per month by visual inspection of the station to assure all equipment is available.

b. At least once per 18 months by removing the hose for inspection and reracking and replacing all gaskets in the couplings that are degraded.

c. At least once per 3 years by:

1. Partially opening each hose station valve to verify valve operability and no flow blockage.

2. Conducting a hose hydrostatic test at a pressure at least 50 psig greater than the maximum pressure available at that hose station.

E. Penetration Fire Barrier

1. Each penetration fire barrier in fire area boundaries shall be verified to be functional by a visual inspection:

a. At least once per 18 months, and

b. Prior to declaring a penetration fire barrier functional following repairs or maintenance.

F. Low Pressure Carbon Dioxide (CO_2) System

1. The CO_2 system for the 4160 volt emergency switchgear vault shall be demonstrated operable:

   a. At least once per week by verifying that the storage tank level is greater than or equal to 1/2 full and the pressure is at least 275 psig.

   b. At least once per month by verifying that each manual valve in the flow path is in its correct position.

   c. At least once per 18 months by verifying that:

      1. The system valves and associated ventilation dampers actuate automatically upon receipt of a simulated actuation signal, and

      2. Flow is observed from each nozzle during a "puff test".

G. Halon Systems

1. Each of the Halon Systems listed in Table 3.12.4 shall be demonstrated operable:

   a. At least once per 6 months by verifying Halon storage tank weight or level and pressure.

   b. At least once per 18 months by:

      1. Verifying the system, including associated ventilation dampers, actuates manually and automatically, upon receipt of a simulated test signal.

      2. Performance of a flow test through headers and nozzles to assure no blockage.

H. Yard Fire Hydrants and Hydrant Hose Houses.

1. Each of the yard fire hydrants and associated hydrant hose houses shown in Table 3.12.5 shall be demonstrated operable:

   a. At least once per 31 days by visual inspection of the hydrant hose house to assure all required equipment is at the hose house.

   b. At least once per 6 months (once during March, April, or May and once during September, October or November) by visually inspecting each yard fire hydrant and verifying that the hydrant barrel is dry and that the hydrant is not damaged.

c. At least once per 12 months by:

1. Conducting a hose hydrostatic test and a pressure at least 50 psig greater than the maximum pressure available at any yard fire hydrant.

2. Inspecting all the gaskets and replacing any degraded gaskets in the couplings.

3. Performing a flow check of each hydrant to verify its operability.

Basis:

Fire Protection systems are normally inactive and require periodic examination and testing to assure their readiness to respond to a fire situation. These specifications detail inspections and tests which will demonstrate that this equipment is capable of performing its intended function.

4.13 ACCIDENT MONITORING INSTRUMENTATION

Applicability: Applies to surveillance requirements for the accident monitoring instrumentation

Objective: To verify the operability of the accident monitoring instrumentation.

Specification: A. Safety & Relief Valve Position Indicators

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the Channel Check and Channel Calibration operations at the frequencies shown in Table 4.13.1.

B. Wide Range Drywell Pressure Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the Channel Check and Channel Calibration operations at the frequencies shown in Table 4.13.1.

C. Wide Range Torus Water Level Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the Channel Check and Channel Calibration operations at the frequencies shown in Table 4.13.1.

D. Drywell H_2 Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the Channel Check and Channel Calibration operations at the frequencies shown in Table 4.13.1.

Bases:

The operability of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. This capability is consistent with NUREGs 0578 and 0737.

TABLE 4.13-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHECK	CALIBRATION
1. Primary and Safety Valve Positon Indicator (Primary Detector*)	A	B
Relief and Safety Valve Position Indicator (Backup Indications**)	A	B
Relief Valve Position Indicator (Common Header Temperature Element**)	C	B***
2. Wide Range Drywell Pressure Monitor (PT/PR 53 & 54)	A	D
3. Wide Range Torus Water Level Monitor (LT/LR 37 & 38)	A	D
4. Drywell H_2 Monitor	A[1]	E

Legend:

A = at least once per 31 days; B = at least once per 18 months (550 days).
C = at least once per 15 days until channel calibration is performed and thence at least once per 31 days.
D = at least once per 6 months; E = at least once per 12 months; 1 = Span and Zero using calibration gases.

* Acoustic Monitor

** Thermocouple

*** This surveillance will commence at the first cold shutdown after July 1, 1985.

SECTION 5

DESIGN FEATURES

5.1 SITE

A. The reactor (center line) is located 1,358 feet west of the east boundary of New Jersey State Highway Route 9 which is the minimum exclusion distance as defined in 10CFR100.3. No part of the property which is closer to the reactor (center line) than 1,358 feet shall be sold or leased.

B. The reactor building, standby gas treatment system and stack shall comprise a secondary containment in such fashion to enclose the primary containment in order to provide for controlled elevated release of the reactor building atmosphere under accident conditions.

5.2 CONTAINMENT

A. The primary containment shall be of the pressure suppression type having a drywell and an absorption chamber constructed of steel. The drywell shall have a volume of approximately 180,000 ft^3 and is designed to conform to ASME Boiler and Pressure Vessel Code, Section VIII, for an internal pressure of 62 psig at 175°F and an external pressure of 2 psig at 150°F to 205°F. The absorption chamber shall have a total volume of approximately 210,000 ft^3. It is designed to conform to ASME Boiler and Pressure Vessel Code, Section VIII, for an internal pressure of 35 psig at 150°F and an external pressure of 1 psig at 150°F.

B. Penetrations added to the primary containment shall be designed in accordance with standards set forth in Section V-1.5 of the facilty Description and Safety Analysis Report. Piping passing through such penetrations shall have isolation valves in accordance with standards set forth in Section V-1.6 of the Facility Description and Safety Analysis Report.

5.3 AUXILIARY EQUIPMENT

5.3.1 Fuel Storage

A. Normal storage for unirradiated fuel assemblies is in critically safe new fuel storage racks in the reactor building storage vault; otherwise, fuel shall be stored in arrays which have a K_{eff} less than 0.95 under optimum conditions of moderation or in NRC-approved shipping containers.

B. The spent fuel shall be stored in the spent fuel storage facility which shall be designed to maintain fuel in a geometry providing a K_{oo} less than or equal to 0.95.

C. The fuel to be stored in spent fuel storage facility shall not exceed a maximum average planar enrichment of 3.01 w/o U-235.

D. Loads greater than the weight of one fuel assembly shall not be moved over stored irradiated fuel in the spent fuel storage facility.

E. The spent fuel shipping cask shall not be lifted more than six inches above the top plate of the cask drop protection system. Vertical limit switches shall be operable to assure the six inch vertical limit is met when the cask is above the top plate of the cask drop protection system.

F. The temperature of the water in the spent fuel stored pool, measured at or near the surface, shall not exceed 125°F.

G. The maximum amount of spent fuel assemblies stored in the spent fuel storage pool shall be 2600.

BASIS

The specification of K_{oo} less than or equal to 0.95 in the spent fuel storage facility assures an ample margin from criticality. Criticality analysis was performed on the poison racks to insure that a K_{oo} of 0.95 would not be exceeded. The basis for this analysis assumed an average planar lattice enrichment of 3.01 w/o U-235 and includes manufacturing tolerances.

The effects of a dropped fuel bundle onto stored fuel in the spent fuel storage facility have been analyzed. This analysis shows that the fuel bundle drop would not cause doses resulting from ruptured fuel pins that exceed 10 CFR 100 limits (1,2,3) and that dropped waste cans will not damage the pool liner.

The elevation limitation of the spent fuel shipping cask to no more than 6 inches above the top plate of the cask drop protection system prevents loss of the pool integrity resulting from postulated drop accidents. An analysis of the effects of a 100 ton cask drop from 6 inches has been done (4) which

showed that the pool structure is capable of sustaining the loads imposed during such a drop. Limit switches on the crane restrict the elevation of the cask to less than or equal to 6 inches when it is above the top plate.

Detailed structural analysis of the spent fuel pool was performed using loads resulting from the dead weight of the structural elements, the building loads, hydrostatic loads from the pool water, the weight of fuel and racks stored in the pool, seismic loads, loads due to thermal gradients in the pool floor and walls, and dynamic load from the cask drop accident. Thermal gradients result in two loading conditions; normal operating and the accident conditions with the loss of spent fuel pool cooling. For the normal condition, the containment air temperature was assumed to vary between 65°F and 110°F while the pool water temperature varied between 85°F and 125°F. The most severe loading from the normal operating thermal gradient results with containment air temperatures at 65°F and the water temperature at 125°F. Air temperature measurements made during all phases of plant operation in the shutdown heat exchanger room, which is directly beneath part of the spent fuel pool floor slab, show that 65°F is the appropriate minimum air temperature. The spent fuel pool water temperature will alarm in the control room before the water temperature reaches 120°F.

Results of the structural analysis show that the pool structure is structurally adequate for the loadings associated with the normal operation and the condition resulting from the postulated cask drop accident (5) (6). The floor framing was also found to be capable of withstanding the steady state thermal gradient conditions with the pool water temperature at 150°F without exceeding ACI Code requirements. The walls are also capable of operation at a steady state condition with the pool water temperature at 140°F (5).

Since the cooled fuel pool water returns at the bottom of the pool and the heated water is removed from the surface, the average of the surface temperature and the fuel pool cooling return water is an appropriate estimate of the average bulk temperature; alternately the pool surface temperature could be conservatively used.

References

1. Amendment No. 78 to the FDSAR (Section 7)
2. Supplement No. 1 to Amendment No. 78 to the FDSAR (Question 12)
3. Supplement No. 1 to Amendment No. 78 of the FDSAR (Question 40)
4. Supplement No. 1 to Amendment No. 68 of the FDSAR.
5. Revision No. 1 to Addendum 2 to Supplement No. 1 to Amendment No. 78 of FDSAR (Questions 5 and 10)
6. FDSAR Amendment No. 79
6. Supplement No. 1 to Amendment No. 68 of the FDSAR.
7. Supplement No. 1 to Amendment No. 78 of the FDSAR (Question 18).
8. Addendum No. 2 to Supplement No. 1 to Amendment No. 78 of the FDSAR (Questions 5 and 10).
9. Revision No. 1 to Addendum 2 to Supplment No. 1 to Amendment No. 78 of the FDSAR (Questions 5 and 10)

ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1

The Vice President & Director Oyster Creek shall be responsible for overall facility operation. Those responsibilities delegated to the Vice President & Director as stated in the Oyster Creek Technical Specifications may also be fulfilled by the Deputy Director. The Vice President & Director shall delegate in writing the succession to this responsibility during his and/or the Deputy Directors absence.

6.2 ORGANIZATION

6.2.1 OFFSITE

The organization for GPU Nuclear Corporation for management and technical support shall be functionally as shown on Figure 6.2.1.

6.2.2 FACILITY STAFF

The facility organization shall be as shown on Figure 6.2.2 and:

a. Each on duty shift shall include at least the shift staffing indicated on Figure 6.2.2.

b. At least one licensed reactor operator shall be in the control room when fuel is in the reactor.

c. Two licensed reactor operators shall be in the control room during all reactor startups, shutdowns, and other periods involving planned control rod manipulations.

d. ALL CORE ALTERATIONS shall be directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

e. An individual qualified in radiation protection measures shall be on site when fuel is in the reactor.

f. A Fire Brigade of at least 5 members shall be maintained onsite at all time. The Fire Brigade shall not include the minimum shift crew necessary for safe shutdown of the facility or any personnel required for other essential functions during a fire emergency.

g. Each on duty shift shall include a Shift Technical Advisor except that the Shift Technical Advisors position need not be filled if the reactor is in the refuel or shutdown mode and the reactor is less than 212°F.

h. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions.

In the event that unforeseen problems require substantial amounts of overtime to be used or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis, the following guidelines shall be followed:

a. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

b. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any seven day period, all excluding shift turnover time.

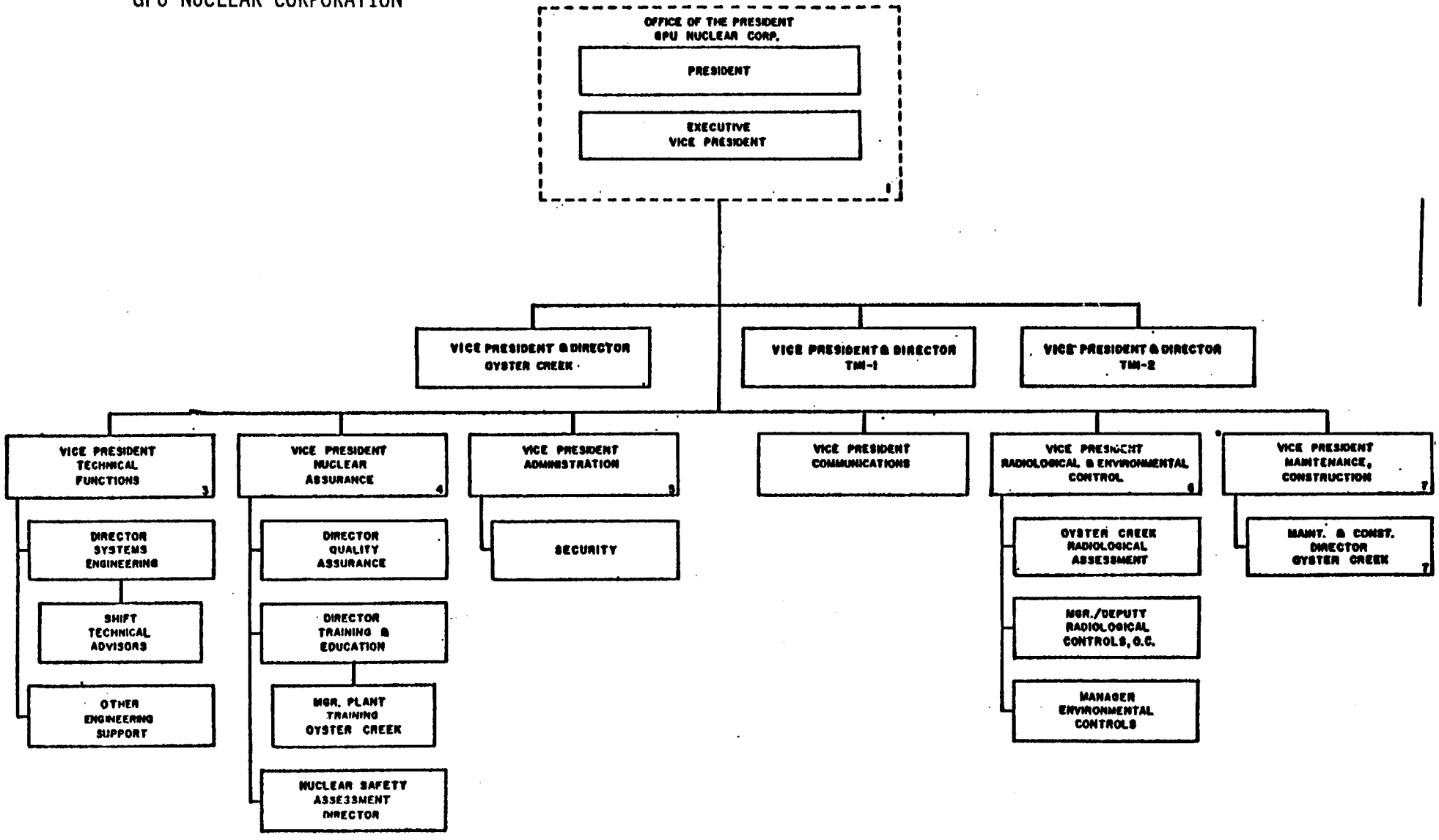
c. A break of at least eight hours should be allowed between work periods, including shift turnover time.

d. In a, b, and c above, the time required to complete shift turnover is to be counted as break time and is not to be counted as work time.

e. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the Department Managers, or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation.

FIGURE 6.2.1
ORGANIZATION CHART
GPU NUCLEAR CORPORATION



NOTES TO FIGURE 6.2.1

1. The project engineering, the shift technical advisors, and licensing functions assigned to each nuclear plant site will report to the Vice President Technical Functions.

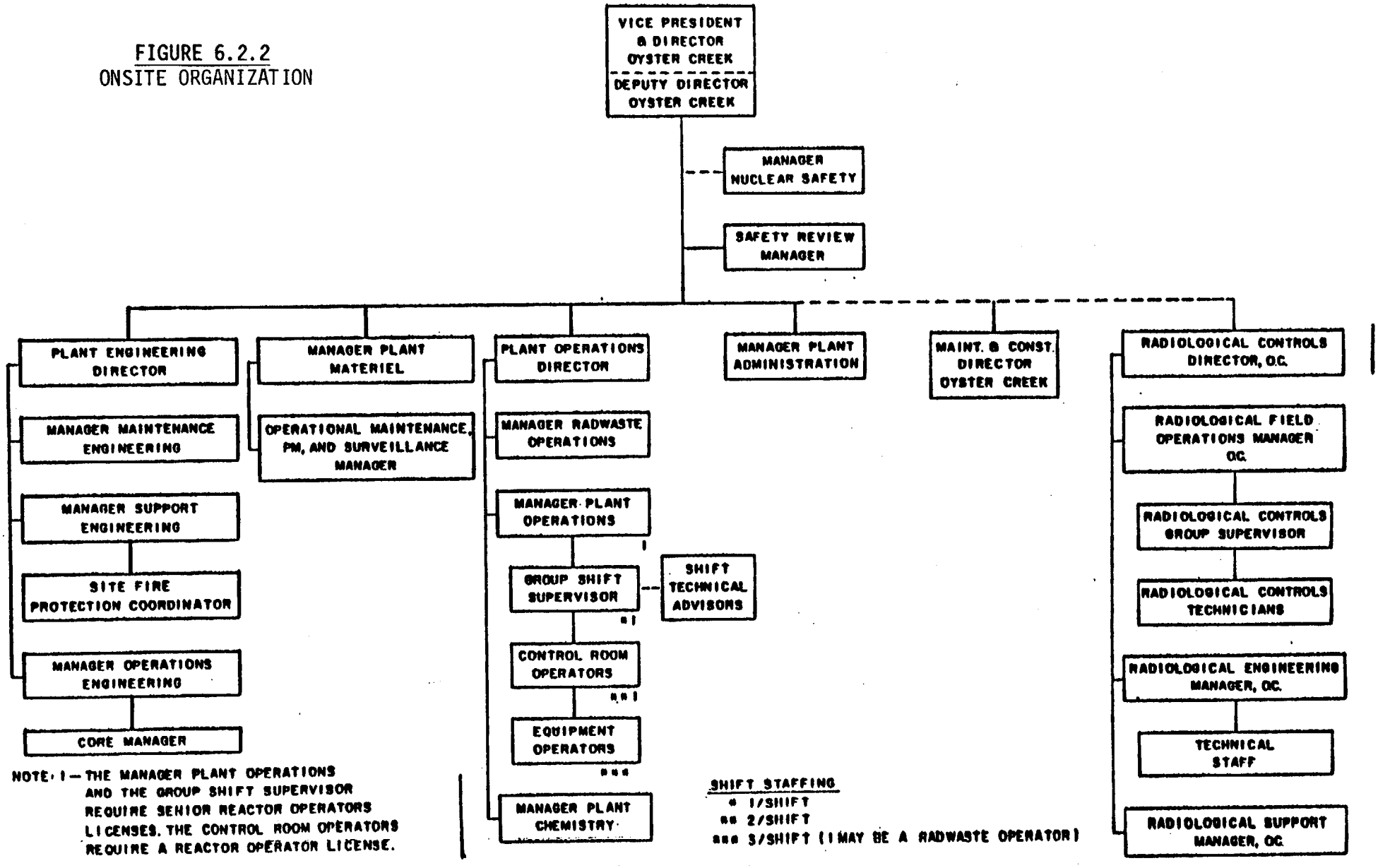
2. The quality assurance, emergency planning and training functions assigned to each nuclear plant site will report to the Vice President Nuclear Assurance.

3. The security, materials management, personnel and general administrative functions assigned to each nuclear plant site will report to the Vice President Administration.

4. The radiological and offsite environmental control functions assigned to each nuclear plant site will report to the Vice President Radiological and Environmental Controls.

5. The conduct of all Oyster Creek modifications, repairs and construction activities will be the responsibility of the Maintenance and Construction Director - Oyster Creek who will report to the Vice President Maintenance and Construction.

FIGURE 6.2.2
ONSITE ORGANIZATION



NOTE: 1 — THE MANAGER PLANT OPERATIONS AND THE GROUP SHIFT SUPERVISOR REQUIRE SENIOR REACTOR OPERATORS LICENSES. THE CONTROL ROOM OPERATORS REQUIRE A REACTOR OPERATOR LICENSE.

6.3 FACILITY STAFF QUALIFICATIONS

6.3.1

The members of the facility staff shall meet or exceed the following qualifications:

Vice President & Director/Deputy Director

Requirements: Ten years total power plant experience of which three years must be nuclear power plant experience. A maximum of four years of academic training may fulfill four of the remaining seven years of required experience. Both must be capable of obtaining or possess a Senior Reactor Operator's License.

Plant Operations Director

Requirements: Eight years total power plant experience of which three years must be nuclear power plant experience. A maximum of two years of academic or related technical training may fulfill two years of the remaining five years of required experience. The Plant Operations Director must be capable of obtaining or possess a Senior Reactor Operator's License.

Plant Engineering Director

Requirements: Eight years of responsible positions related to power generation, of which three years shall be nuclear power plant experience. A maximum of four of the remaining five years of experience may be fulfilled by satisfactory completion of academic or related technical training.

Manager-Plant Administration

Requirements: Eight years total power plant experience of which four years must have been in nuclear power plant experience. The Manager should possess a four year college degree or equivalent in Business Administration or an Engineering discipline.

Manager-Plant Operations

Requirements: Eight years total power plant experience of which three years must be nuclear power plant experience. A maximum of two years of academic or related technical training may fulfill two of the remaining five years of required experience. The Manager Plant Operations must possess a Senior Reactor Operator's License.

Manager-Plant Chemistry

Requirements: Five years experience in chemistry of which a minimum of one year shall be in radiochemistry at an operating nuclear power plant. A maximum of four years of this five year experience may be fulfilled by related technical or academic training.

Safety Review Manager

Requirements: Eight years total power plant experience of which three years must be nuclear power plant experience. A maximum of two years of academic or related technical training may fulfill two of the remaining five years of required experience.

Manager-Plant Material

Requirements: Seven years of total power plant experience of which one year must be nuclear power plant experience. Two years of academic or related technical training may fulfill two of the remaining six years of required experience.

Area Supervisor-Instrument and Computer Maintenance

Requirements: Five years of experience in instrumentation and control, of which a minimum of one year shall be in nuclear instrumentation and control at an operating nuclear power plant. A maximum of four years of this five year experience may be fulfilled by related technical or academic training.

Managers-Plant Engineering

The engineers in charge of technical support shall have a Bachelor's Degree in Engineering or the Physical Sciences and have three years of professional level experience in nuclear services, nuclear plant operation, or nuclear engineering, and the necessary overall nuclear background to determine when to call consultants and contractors for dealing with complex problems beyond the scope of owner-organization expertise.

Core Manager

At the time of initial core loading or appointment to the position, whichever is later, the responsible person shall have a Bachelor's Degree in Engineering or the Physical Sciences and four years experience or a graduate degree and three years experience. Two of these years shall be nuclear power plant experience. The experience shall be in such areas as reactor physics, core measurements, core heat transfer, and core physics testing programs. Successful completion of a reactor engineering training program (such as the 12 week concentrated programs offered by NSS Vendors) may be equivalent to one year's nuclear power plant experience.

Radiological Controls Director (Reports Offsite)

Requirements: Bachelor's degree or the equivalent in a science or engineering subject, including some formal training in radiation protection. Five years of professional experience in applied radiation protection. (Master's degree equivalent to one year experience and Doctor's degree equivalent to two years experience where coursework related to radiation protection is involved.) Three years of this professional experience should be in applied radiation protection

work in a nuclear facility dealing with radiological problems similar to those encountered in nuclear power stations.

M&C Director, O.C.

Requirements: Seven years of total power plant experience of which one year must be nuclear power plant experience. Two years of academic or related technical training may fulfill two of the remaining six years of required experience.

Shift Technical Advisor

Requirements: Bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design, and response and analysis of the plant for transients and accidents.

6.3.2

Each member of the radiation protection organization for which there is a comparable position described in ANSI N18.1-1971 shall meet or exceed the minimum qualifications specified therein, or in the case of radiation protection technicians, they shall have at least one year's continuous experience in applied radiation protection work in a nuclear facility dealing with radiological problems similar to those encountered in nuclear power stations and shall have been certified by the Radiological Controls Director, as qualified to perform assigned functions. This certification must be based on an NRC approved, documented program consisting of classroom training with appropriate examinations and documented positive findings by responsible supervision that the individual has demonstrated his ability to perfrom each specified procedure and assigned function with an understanding of its basis and purpose.

6.4 TRAINING

6.4.1

A retraining program for operators shall be maintained under the direction of the Manager Plant Training Oyster Creek and shall meet the requirements and recommendation of Appendix A of 10CFR Part 55. Replacement training programs, the content of which shall meet the requirements of 10CFR Part 55, shall be conducted under the direction of the Manager Plant Training Oyster Creek for licensed operators and Senior Reactor Operators.

6.4.2

A training program for the Fire Brigade shall be maintained under the direction of the Manager Plant Training Oyster Creek.

6.5 REVIEW AND AUDIT

6.5.1 TECHNICAL REVIEW AND CONTROL

The Vice President of each division within GPU Nuclear Corporation as indicated in Figure 6.2.1, shall be responsibile for ensuring the preparation, review, and approval of documents required by the activities described in 6.5.1.1 through 6.5.1.5 within his functional area of responsibility as assigned in the GPUN Review and Approval Matrix. Implementing approvals shall be performed at the cognizant manager level or above.

ACTIVITIES

6.5.1.1

Each procedure required by Technical Specification 6.8 and other procedures including those for tests and experiments which are important to safety, and changes thereto which are important to safety, shall be prepared by a designated individual(s)/group knowledgeable in the area affected by the procedure. Each such procedure, and change thereto, shall be reviewed for adequacy by an individual(s)/group other than the preparer, but who may be from the same division as the individual who prepared the procedure or change.

6.5.1.2

Proposed changes to the Appendix "A" Technical Specifications shall be reviewed by a knowledgeable individual(s)/group other than the individual(s)/group who prepared the change.

6.5.1.3

Proposed modifications to facility structures, systems and components important to safety shall be designed by an individual/organization knowledgeable in the areas affected by the proposed modification. Each such modification shall be reviewed by an individual/group other than the individual/group which designed the modification but may be from the same division as the individual who designed the modification.

6.5.1.4

Proposed tests and experiments that are important to safety shall be reviewed by a knowledgeable individual(s)/group other than the preparer but who may be from the same division as the individual who prepared the tests and experiments.

6.5.1.5

Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, shall be reviewed by a knowledgeable individual(s)/group other than the individual/group which performed the investigation.

6.5.1.6

Events requiring 24-hour written notification to the Commission shall be reviewed by an individual/group other than the individual/group which prepared the report.

6.5.1.7

Special reviews, investigations or analyses and reports thereon as requested by the Vice President & Director Oyster Creek shall be performed by a knowledgeable individual(s)/group.

6.5.1.8

The Security Plan and implementing procedures shall be reviewed by a knowledgeable individual(s)/group other than the individual(s)/group which prepared them.

6.5.1.9

The Emergency Plan and implementing procedures shall be reviewed by a knowledgeable individual(s)/group other than the individual(s)/group which prepared them.

6.5.1.10

Review of every unplanned onsite release of radioactive material to the environs including the preparation and forwarding of reports covering evaluation shall be performed by a knowledgeable individual(s)/group. Recommendations and disposition of the corrective action to prevent recurrence shall be sent to the Vice President & Director Oyster Creek.

6.5.1.11

Major changes to radwaste systems shall be reviewed by a knowledgeable individuals(s)/group other than the individual(s)/group which prepared them.

6.5.1.12

Individuals responsible for reviews performed in accordance with 6.5.1.1 through 6.5.1.4 shall include a determination of whether or not additional cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the appropriate personnel. Individuals responsible for reviews considered under 6.5.1.1 through 6.5.1.5 shall render determinations in writing with regard to whether or not 6.5.1.1 through 6.5.1.5 constitute an unreviewed safety question.

RECORDS

6.5.1.13

Written records of activities performed under specifications 6.5.1.1 through 6.5.1.11 shall be maintained.

QUALIFICATIONS

6.5.1.14

Responsible Technical Reviewers shall meet or exceed the qualifications of ANSI N18.1-1978 Section 4.6 or 4.4 for applicable disciplines or have 7 years of appropriate experience in the field of his specialty. Credit towards experience will be given for advanced degrees on a one for one basis up to a maximum of two years. These Reviewers shall be designated in writing.

6.5.2 INDEPENDENT SAFETY REVIEW

FUNCTION

6.5.2.1

The Vice President of each division within GPU Nuclear Corporation as indicated in Figure 6.2.1 shall be responsible for ensuring the periodic independent safety review of the subjects described in 6.5.2.5 within his assigned area of safety review responsibility, as assigned in the GPUN Review and Approval Matrix.

6.5.2.2

Independent safety review shall be completed by an individual/group not having direct responsibility for the performance of the activities under review, but who may be from the same functionally cognizant organization as the individual/group performing the original work.

6.5.2.3

GPU Nuclear Corporation shall collectively have or have access to the experience and competence required to independently review subjects in the following areas:

a. Nuclear power plant operations
b. Nuclear engineering
c. Chemistry and radiochemistry
d. Metallurgy
e. Nondestructive testing
f. Instrumentation and control
g. Radiological safety
h. Mechanical engineering
i. Electrical engineering
j. Administrative controls and quality assurance practices

k. Emergency plans and related organization, procedures and equipment

l. Other appropriate fields associated with the unique characteristics of Oyster Creek

6.5.2.4

Consultants may be utilized as determined by the cognizant Vice President to provide expert advice.

RESPONSIBILITIES

6.5.2.5

The following subjects shall be independently reviewed by the functionally assigned divisions:

a. Written safety evaluations of changes in the facility as described in the Safety Analysis Report, of changes in procedures as described in the Safety Analysis Report, and of tests or experiments not described in the Safety Analysis Report, which are completed without prior NRC approval under the provisions of 10CFR 50.59(a)(1). This review is to verify that such changes, tests or experiments did not involve a change in the Technical Specifications or an unreviewed safety question as defined in 10CFR 50.59(a)(2). Such reviews need not be performed prior to implementation.

b. Proposed changes in procedures, proposed changes in the facility, or proposed tests or experiments, any of which involves a change in the Technical Specifications or an unreviewed safety question as defined in 10CFR 50.59(c). Matters of this kind shall be reviewed prior to submittal to the NRC.

c. Proposed changes to Technical Specifications or license amendments related to nuclear safety shall be reviewed prior to submittal to the NRC for approval.

d. Violations, deviations, and reportable events which require reporting to the NRC in writing. Such reviews are performed after the fact. Review of events covered under this subsection shall include results of any investigations made and the recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event.

e. Written summaries of audit reports in the areas specified in section 6.5.3 and involving safety related functions.

f. Any other matters involving safe operation of the nuclear power plant which a reviewer deems appropriate for consideration, or which is referred to the independent reviewers.

QUALIFICATIONS

6.5.2.6

The independent reviewer(s) shall either have a Bachelor's Degree in Engineering or the Physical Sciences and five (5) years of professional level experience in the area being reviewed or have 9 years of appropriate experience in the field of his specialty. An individual performing reviews may possess competence in more than one specialty area. Credit toward experience will be given for advanced degrees on a one-for-one basis up to a maximum of two years.

RECORDS

6.5.2.7

Reports of reviews encompassed in Section 6.5.2.5 shall be prepared, maintained and transmitted to the cognizant division Vice President.

6.5.3 AUDITS

6.5.3.1

Audits of facility activities shall be performed under the cognizance of the Vice President Nuclear Assurance. These audits shall encompass:

a. The conformance of facility operations to provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months.

b. The performance, training and qualifications of the facility staff at least once per 12 months.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems or method of operation that affect nuclear safety at least once per six months.

d. The Facility Emergency Plan and implementing procedures at least once per 12 months.

e. The Facility Security Plan and implementing procedures at least once per 12 months.

f. The Fire Protection Program and implementing procedures at least once per 24 months.

g. The performance of activities required by the Operational Quality Assurance Plan to meet the criteria of Appendix 'B', 10CFR50, at least once per 24 months.

h. Any other area of facility operation considered appropriate by the IOSRG or the Office of the President-GPUNC.

6.5.3.2

Audits of the following shall be performed under the cognizance of the Vice President - Technical Functions:

a. An independent fire protection and loss prevention program inspection and audit shall be performed annually utilizing either qualified offsite licensee personnel or an outside fire protection firm.

b. An inspection and audit of the fire protection and loss prevention program, by an outside qualified fire consultant at intervals no greater than 3 years.

RECORDS

6.5.3.3

Audit reports encompassed by sections 6.5.3.1 and 6.5.3.2 shall be forwarded for action to the management positions responsible for the areas audited within 60 days after completion of the audit. Upper management shall be informed per the Operation Quality Assurance Plan.

6.5.4 INDEPENDENT ONSITE SAFETY REVIEW GROUP (IOSRG)

STRUCTURE

6.5.4.1

The IOSRG shall be a full-time group of engineers experienced in nuclear power plant engineering, operations and/or technology, independent of the facility staff, and located onsite.

ORGANIZATION

6.5.4.2

a. The IOSRG shall consist of the Manager - Nuclear Safety and staff members who meet the qualifications of 6.5.4.5. Group expertise shall be multidisciplined.

b. The IOSRG shall report to the Nuclear Safety Assessment Director.

FUNCTION

6.5.4.3

The periodic review functions of the IOSRG shall include the following on a selective and overview basis:

1) Evaluation for technical adequacy and clarity of procedures important to the safe operation of the facility.

2) Evaluation of facility operations from a safety perspective.

3) Assessment of facility nuclear safety programs.

4) Assessment of the facility performance regarding conformance to requirements related to safety.

5) Any other matter involving safe operation of the nuclear power plant that the Manager - Nuclear Safety deems appropriate for consideration.

AUTHORITY

6.5.4.4

The IOSRG shall have access to the facility and facility records as necessary to perform its evaluations and assessments. Based on its reviews, the IOSRG shall provide recommendations to the management positions responsible for the areas reviewed.

QUALIFICATIONS

6.5.4.5

IOSRG engineers shall have either (1) a Bachelor's Degree in Engineering or appropriate Physical Science and three years of professional level experience in the nuclear power field which may include technical supporting functions or (2) eight years of appropriate experience in nuclear power plant operations and/or technology. Credit toward experience will be given for advance degrees on a one-to-one basis up to a maximum of two years.

RECORDS

6.5.4.6

Reports of evaluations and assessments encompassed in Section 6.5.4.3 shall be prepared, approved, and transmitted to the Nuclear Safety Assessment Director, Oyster Creek and Nuclear Assurance division Vice Presidents, and the management positions responsible for the areas reviewed.

6.6 REPORTABLE EVENT ACTION

6.6.1

The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and a report submitted pursuant to the requirements of Section 50.73 to 10 CFR Part 50; and

b. Each REPORTABLE EVENT shall be reported to the cognizant manager and the cognizant division Vice President and the Vice President &

Director Oyster Creek. The functionally cognizant division staff shall prepare a Licensee Event Report (LER) in accordance with the guidance outlined in 10 CFR 50.73(b). Copies of all such reports shall be submitted to the functionally cognizant division Vice President and the Vice President Director & Oyster Creek.

6.7 SAFETY LIMIT VIOLATION

6.7.1

The following actions shall be taken in the event a Safety Limit is violated:

a. If any Safety Limit is exceeded, the reactor shall be shut down immediately until the Commission authorizes the resumption of operation.

b. The Safety Limit violation shall be reported to the Commission and the Vice President and Director Oyster Creek.

c. A Safety Limit Violation Report shall be prepared. The report shall be submitted to the Vice President and Director Oyster Creek. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components systems or structures, (3) corrective action taken to prevent recurrence.

d. The Safety Limit Violation Report shall be submitted to the Commission within 10 days of the violation.

6.8 PROCEDURES

6.8.1

Written procedures shall be established, implemented, and maintained that meet or exceed the requirements of the Nuclear Regulatory Commission's Regulatory Guide 1.33 (the applicable revision is identified in the GPU Nuclear Operational Quality Assurance Plan) and as provided in 6.8.2 and 6.8.3 below.

6.8.2

Each procedure and administrative policy of 6.8.1 above, and changes thereto, shall be reviewed as described in 6.5.1.1 and approved as described in 6.5.1 prior to implementation and periodically as specified in the Administrative Procedures.

6.8.3

Temporary changes to procedures 6.8.1 above may be made provided:

a. The intent of the original procedure is not altered.

b. The change is approved by two members of GPUNC Management Staff authorized under Section 6.5.1.12 and knowledgeable in the area

affected by the procedure. For changes which may affect the operational status of facility systems or equipment, at least one of these individuals shall be a member of facility management or supervision holding a Senior Reactor Operator's License on the facility.

c. The change is documented, subsequently reviewed and approved as described in 6.8.2 within 14 days of implementation.

6.9 REPORTING REQUIREMENTS

In addition to the applicable reporting requirements of 10 CFR, the following identified reports shall be submitted to the Director of the appropriate Regional Office of Inspection and Enforcement unless otherwise noted.

6.9.1 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 specified 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 commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

b. Annual Exposure Data Report. Routine exposure data reports covering the operation of the facility during the previous calendar year shall be submitted prior to March 1 of each year. Reports shall contain a tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures greater than 100 mrem/year and their associated man rem exposure according to work and job functions (This tabulation supplements the requirements of 10 CFR 20.407), 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.

c. Monthly Operating Report. Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis which will include a narrative of operating experience, to the Director, Office of Management and Program Control, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Office of I&E, no later than the 15th of each month following the calendar month covered by the report.

6.9.2 REPORTABLE EVENTS

The submittal of Licensee Event Reports shall be accomplished in accordance with the requirements set forth in 10 CFR 50.73.

6.9.3 UNIQUE REPORTING REQUIREMENTS

Special reports shall be submitted to the Director of Regulatory Operations Regional Office within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification.

a. Materials Radiation Surveillance Specimen Reports (4.3A)

b. Integrated Primary Containment Leakage Tests (4.5)

c. Semi-annual reports specifying effluent release shall be submitted to the NRC. These reports shall include the following:

(1) Radioactive Effluent Releases

A statement of the quantities of radioactive effluents released from the plant with data summarized on a monthly basis following the format of USAEC Guide 1.21.

(a) Gaseous Effluents

1. Gross Radioactivity Releases

a. Total gross radioactivity (in curies), primarily noble and activation gases.

b. Maximum gross radioactivity release rate during any one-hour period.

c. Total gross radioactivity (in curies) by nuclide release based on representative isotopic analyses performed.

d. Percent of technical specification limit.

2. Iodine Releases

a. Total iodine radioactivity (in curies) by nuclide released based on representative isotopic analyses performed.

b. Percent of technical specification limit for I-131 released.

3. Particulate Releases

a. Total gross radioactivity (β, γ) released (in curies excluding background radioactivity.

b. Gross alpha radioactivity released (in curies) excluding background radioactivity.

c. Total gross radioactivity (in curies) of nuclides with half-lives greater than eight days.

d. Percent of technical specification limit for particulate radioactivity with half-lives greater than eight days.

4. Liquid Effluents

a. Total gross radioactivity (β, γ) released (in curies) excluding tritium and average concentration released to the unrestricted area.

b. The maximum concentration of gross radioactivity (β, γ) released to the unrestricted area (averaged over the period of release).

c. Total tritium and total alpha radioactivity (in curies) released and average concentration released to the unrestricted area.

d. Total dissolved gas radioactivity (in curies) and averaged concentration released to the unrestricted area.

e. Total volume (in liters) of liquid waste released.

f. Total volume (in liters) of dilution water used prior to release from the restricted area.

g. Total gross radioactivity (in curies) by nuclide released based on representative isotopic analyses performed.

h. Percent of technical specification limit for total radioactivity.

(2). Solid Waste

(a). The total amount of solid waste shipped (in cubic feet).

(b). The total estimated radioactivity (in curies) involved.

(c). Disposition including date and destination.

(3). Environmental Monitoring

(a). For each medium sampled during the reporting period, e.g., air, baybottom, surface water, soil, fish, include:

1. Number of sampling locations.

2. Total number of samples.

3. Number of locations at which levels are found to be significantly above local backgrounds, and

4. Highest, lowest, and the average concentrations or level of radiation for the sampling point with the highest average and description of the location of that point with respect to the site.

(b). If levels of radioactive materials in environmental media as determined by an environmental monitoring program indicate the likelihood of public intakes in excess of 1% of those that could result from continuous exposure to the concentration values listed in Appendix B, Table II, Part 20 estimates of the likely resultant exposure to individuals and to population groups, and assumptions upon which estimates are based shall be provided.

(c). If statistically significant variations of offsite environmental concentrations with time are observed, correlation of these results with effluent release shall be provided.

(d). Results of required leak tests performed on sealed sources if the tests reveal the presence of 0.005 microcuries or more of removable contamination.

d. Inoperable Fire Protection Equipment (3.12)

e. Core Spray Sparger Inservice Inspection (Table 4.3.1-9)

Prior to startup of each cycle, a special report presenting the results of the inservice inspection of the Core Spray Spargers during each refueling outage shall be submitted to the Commission for review.

f. Failures and challenges to Relief and Safety Valves

Failures and challenges to Relief and Safety Valves which do not constitute an LER will be the subject of a special report submitted to the Commission within 60 days of the occurrence. A challenge is defined as any automatic actuation (other than during surveillance or testing) of Safety or Relief Valves.

6.10 RECORD RETENTION

6.10.1

The following records shall be retained for at least five years:

a. Records and logs of facility operation covering time interval at each power level.

b. Records and logs of principle maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. Reportable occurrence reports.

d. Records of surveillance activities, inspections and calibrations required by these technical specifications.

e. Records of reactor tests and experiments.

f. Records of changes made to operating procedures.

g. Records of radioactive shipments.

h. Records of sealed source leak tests and results.

i. Records of annual physical inventory of all source material of record.

6.10.2

The following records shall be retained for the duration of the Facility Operating License:

a. Record and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of facility radiation and contamination surveys.

d. Records of radiation exposure for all individuals entering radiation control areas.

e. Records of gaseous and liquid radioactive material released to the environs.

f. Records of transient or operational cycles for those facility components designed for a limited number of transients or cycles.

g. Records of training and qualification for current members of the plant staff.

h. Records of inservice inspections performed pursuant to these technical specifications.

i. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.

j. Records of reviews by the Independent Onsite Safety Review Group.

k. Records for Environmental Qualification which are covered under the provisions for paragraph 6.14.

l. Records of the service lives of all snubbers, including the date at which the service life commences, and associated installation and maintenance records.

6.10.3

Quality Assurance Records shall be retained as specified by the Quality Assurance Plan.

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 (Deleted)

6.13 HIGH RADIATION AREA

6.13.1

In lieu of the "control device" or "alarm signal" required by paragraph 20.203(c)(2) of 10 CFR 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shal be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP).

NOTE: Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they are following plant radiation protection procedures for entry into high radiation areas.

An individual or group of individuals permitted to enter such areas shall be provided with one or more of the following:

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a pre-set integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been amde knowledgeable of them.

c. A health physics qualified individual (i.e. qualified in radiation protection procedures) with a radiation dose rate monitoring device who is responsible for providing positive exposure control over the activities within the area and who will perform periodic radiation surveillance at the frequency in the RWP. The surveillance frequency will be established by the Radiological Controls Manager.

6.13.2

Specification 6.13.1 shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mrem/hr. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of operations and/or radiation protection supervision on duty.

6.14 ENVIRONMENTAL QUALIFICATION

A. By no later than June 30, 1982 all safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: Division of Operating Reactors "Guidelines for Evaluating Environmental Qualification of Class IE Electrical Equipment in Operating Reactors" (DOR Guidelines); or, NUREG-0588 "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," December 1979. Copies of these documents are attached to Order for Modification of License DPR-16 dated October 24, 1980.

B. By no later than December 1, 1980, complete and auditible records must be available and maintained at a central location which describe the environmental qualification method used for all safety-related electrical equipment in sufficient detail to document the degree of compliance with the DOR Guidelines or NUREG-0588. Thereafter, such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.15 Integrity of Systems Outside Containment

The licensee shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

1) Provisions establishing preventive maintenance and periodic visual inspection requirements, and

2) System leak test requirements, to the extent permitted by system design and radiological conditions, for each system at a frequency not to exceed refueling cycle intervals. The systems subject to this testing are (1) Core Spray, (2) Containment Spray, (3) Reactor Water Cleanup, (4) Isolation Condenser and (5) Shutdown Cooling.

6.16 Iodine Monitoring

The licensee shall implement a program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas* under accident conditions. This program shall include the following:

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

6.17 The following program shall be established, implemented, and maintained.

Post Accident Sampling

A program has been established which will ensure the capability to obtain and analyze reactor coolant, radioactive iodines and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. The program shall include the following:

1. Training of personnel in sampling and analysis

2. Procedures for sampling and analysis

3. Provisions for verifying operability of the System.

*Areas requiring personnel access for establishing hot shutdown condition.