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SECTION 1

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 attendent 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.

*The time between successive tests or surveillance 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 MWT. The 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 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.

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. 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.

*Not applicable to containment leak rate test

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 600 psia, the combination of reactor core flow and reactor thermal power to water shall not exceed the limit shown on Figure 2.1.1. for any fuel type.

A.1 Figure 2.1.1. applies directly when the total peaking factor is less than or equal to the following:

Fuel Type IIIF

a. Axial peak at core midplane or below of	2.74
b. Axial peak above core midplane of	2.50

For 8 x 8 Fuel

a. Axial peak at core midplane or below of	2.78
b. Axial peak above midplane of	2.61

A.2 For total peaking factors greater than those specified in Specification 2.1.A.1, the safety limit is reduced by the following:

$$SL = SLo \times (PFo/PF)$$

where: SL = reduced safety limit
SLo= safety limit from figure 2.1.1.
PFo= peaking factor specified in Specification 2.1.A.1
PF = actual peaking factor

B. When the reactor pressure is less than 600 psia or reactor flow is less than 10 percent of rated, the reactor thermal power shall not exceed 354 Mwt.

C. The neutron flux shall not exceed its scram setting for longer than 1.75 seconds.

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 the normal active fuel zone.

E. The existence of a minimum critical power ratio (MCPR) less than 1.32 for 7 x 7 fuel and 1.34 for 8 x 8 fuel shall constitute violation of the fuel cladding integrity safety limit.

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

A critical heat flux occurrence results in a decrease in heat transferred from the clad and, therefore, high clad temperatures and the possibility of clad failure. However, the existence of a critical heat flux occurrence is not a directly observable parameter in an operating reactor. Furthermore, the critical heat flux correlation data which relates observable parameters to the critical heat flux magnitude is statistical in nature.

The margin to boiling transition is calculated from plant operating parameters such as core pressure, core flow, feedwater temperature, core power, and core power distribution. The margin for each fuel assembly is characterized by the critical power ratio (CPR) which is the ratio of the bundle power which would produce onset of transition boiling divided by the actual bundle power. The minimum value of this ratio for any bundle in the core is the minimum critical power ratio (MCPR)(10).

The safety limit curves shown in Figure 2.1.1. represent conditions which assure with better than 95 percent confidence a 95 percent probability of avoiding a critical heat flux occurrence. The critical power value was determined using the design basis critical power correlation given in Reference 1. The operating range with MCPR greater than 1.32 for 7 x 7 fuel and 1.34 for 8 x 8 fuel is below and to the right of these curves.

The design basis critical heat flux correlation is based on an interrelationship of reactor coolant flow and steam quality. Steam quality is determined by reactor power, pressure, and coolant inlet enthalpy which in turn is a function of feedwater temperature and water level. This correlation is based upon experimental data taken over the entire pressure range of interest in a BWR, and the correlating line was determined by the statistical mean of the experimental data.

Curves are presented for two different pressures in Figures 2.1.1. The upper curve is based on nominal operating pressure of 1035 psia. The lower curve is based on a pressure of 1250 psia. In no case is reactor pressure ever expected to exceed 1250 psia because of protection system settings well below this value and, therefore, the curves will cover all operating conditions with interpolation. For pressures between 600 psia (the lower end of the critical heat flux correlation data) and 1035 psia, the upper curve is applicable with increased margin.

The power shape used in the calculation of Figure 2.1.1 is given in Table 3.2 of Reference 10 for a peak to average power of 1.5 with a peak location at the core midplane (X/L = 0.5). Table 3.2 further shows an axial power shape with an axial peak of the same magnitude but with a peak location above the core midplane (X/L = 0.65). These power shapes result in total peaking factors for each fuel type as shown in Specification 2.1.A.1. The total peaking factor for each fuel type is to be less than that specified in Section 1.1.A.1 at rated power. When operating below rated power with higher peaking factors as during control rod manipulation or near end of core life, applicability of the safety limit is assured by applying the reduction factors specified in 2.1.A.2.

The feedwater temperature assumed was the maximum design temperature output of the feedwater heaters at the given pressures and flows (e.g., 334^{0}F at 1035 psia and 100% flow). For any lower feedwater temperature, subcooling is increased and the curves provide increased margin.

The water level assumed in the calculations was ten inches below the reactor low water level scram point (10'-7" above the top of the active fuel), which is the location of the bottom of the steam separator skirts. Of course, the reactor could not be operated in this condition. As long as the water level is above this point, the safety limit curves are applicable. As long as the water level is above the bottom of the steam separator skirts, the amount of carryunder would not be increased and the core inlet enthalpy would not be influenced.

The values of the parameters involved in Figure 2.1.1 can be determined from information available in the control room. Reactor pressure and flow are recorded and the APRM in-core nuclear instrumentation is calibrated in terms of percent power.

The range in pressure used for Specification 2.1.A in the calculation of the fuel cladding integrity safety limit is from 600 to 1250 psia. Specification 2.1.B provides a requirement on

power level when operating below 600 psia or 10% flow. In general, Specification 2.1.B will only be applicable during startup or shutdown of the plant. A review of all the applicable low pressure and low flow data (6,7) has shown the lowest data point for transition boiling to have a heat flux of 144,000 BTU/hr-ft2. To insure applicablility to the BWR fuel rod geometry, and provide a margin, a factor of one-half was used, giving a critical heat flux of 72,000 BTU/hr-ft2. This is equivalent to a core average power of 354 MWt (18.3% of rated). This value is applicable to ambient pressure and no flow conditions. For any greater pressure or flow conditions, there is increased margin.

During transient operation, the heat flux (thermal power-to-water) would lag behind the neutron flux due to the inherent heat transfer time constant of the fuel of 8-9 seconds. Also, the limiting safety system scram settings are at values which will not allow the reactor to be operated above the safety limit during normal operation or during other plant operating situations which have been analyzed in detail (2,3,4,8,9,10).

If the scram occurs such that the neutron flux dwell time above the limiting safety system setting is less than 1.75 seconds, the safety limit will not be exceeded for normal turbine or generator trips, which are the most severe normal operating transients expected. Following a turbine or generator trip, if it is determined that the bypass system malfunctioned, analysis of plant data will be used to ascertain if the safety limit has been exceeded, according to Specification 2.1.A. The dwell time of 1.75 seconds in Specification 2.1.C provides increased margin for less severe power transients.

Should a power transient occur, the event recorder would show the time interval the neutron flux is over its scram setting. When the event recorder is out of service, a safety limit violation will be assumed if the neutron flux exceeds the scram setting and control rod scram does not occur. The event recorder shall be returned to an operable condition as soon as practical.

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.

The lowest point at which the water level can presently be monitored is 4'-8" above the top of the 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 established at 4'-8" to provide a point which can be monitored.

Specification F 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 truly indicative of the water level in the core region.

<u>References</u>

(1) XN-75-34, Revision 1, The XN-2 Critical Power Correlation, Exxon Nuclear Company, Inc., August 1, 1975.

(2) FDSAR, Volume I, Section 1.5-6.

(3) Licensing Application Amendment 28, Question III.A-12.

(4) Licensing Application Amendment 32, Question 13.

(5) FDSAR, Volume I, Section SII-7.3.

(6) E. Janssen, "Multirod Burnout at Low Pressure", ASME Paper 62-HT-26, August 1962.

(7) K.M. Becker, "Burnout Conditions for Flow of Boiling Water in Vertical Rod Clusters", AE-74 (Stockholm, Sweden). May 1962.

(8) Licensing Application Amendment 55, Sections 4.

(9) Licensing Application Amendment 65, Sections B.IV, B.VIII, B.XI

(10) Licensing Application Amendment 76 (Supplement No. 4).

(11) Deleted

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 = 1375 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 over-pressurization analysis (2) is performed 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 continously monitored in the control room during reactor operation on the 1600 psi full scale pressure recorder

with an error of less than 1% and a recorder time response of one second.

References

(1) FDSAR, Volume I, Section IV.

(2) License Application, Amendment 76.

(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
1) Neutron Flux, Scram	
a) APRM	For recirculation flow, W less than or equal to 61.0E6 lb/hr: less than or equal to ((1.34E-6) W + 34.0) percent of rated neutron flux when total peaking factors in all fuel types are less than or equal to those in Specification 2.1.A.1, or The lowest value of: less than or equal to ((1.34E-6) W + 34.0) (PFo/PF) percent of rated neutron flux from among those calculations for each fuel type with total peaking factors, PF greater than PFo, where PFo = peaking factor in Specification 2.1.A.1 For recirculation flow, W greater than 61.0E6 lb/hr: less than or equal to 115.7 percent of rated neutron flux when total peaking factors in all fuel types are less than or equal to those in Specification 2.1.A.1, or The lowest value of: less than or equal to 115.7 (PFo/PF) percent of rated neutron flux from among those calculations for each fuel type with total peaking factors

PF greater than PFo, where PFo = peaking factor in Specification 2.1.A.1.

b) IRM — less than or equal to 15 percent of rated neutron flux

2) Neutron Flux, Control Rod Block

a) For recirculation flow, W less than or equal to 61.0E6 lb/hr:

less than or equal to ((1.34E-6) W + 24.3) percent of rated neutron flux when total peaking factors in all fuel types are less than or equal to those in Specification 2.1.A.1, or

The lowest value of:

less than or equal to ((1.34E-6) W + 24.3) (PFo/PF) percent of rated neutron flux from among those calculated for each fuel type with total peaking factors, PF greater than PFo, where PFo = peaking factor in greater than Specification 2.1.A.1

For recirculation flow, W greater than 61.0E6 lb/hr:

less than or equal to 106 percent of rated neutron flux when total peaking factors in all fuel types are less than or equal to those in Specification 2.1.A.1, or

The lowest value of:

less than or equal to 106 (PFo/PF) percent of rated neutron flux from among those calculated for each fuel type with total peaking factors, PF greater than PFo, where PFo = peaking factor in Specification 2.1.A.1

3) Reactor High Pressure, Scram — less than or equal to 1060 psig.

4) Reactor High Pressure, Relief Valves Initiation — 2 valves less than or equal to 1070 psig; 3 valves less than or equal to 1090 psig

5) Reactor High Pressure, Isolation Condenser Initiation — 1060 psig with time delay less than or equal to 15 seconds

6) Reactor High Pressure, — 4 @ 1212 psig

Safety Valve Initiation	4 @ 1221 psig 4 @ 1230 psig 4 @ 1239 psig	plus or minus 12 psi
7) Low Pressure Main Steam Line, MSIV Closure	greater than or equal to 825 psig	
8) Main Steam Line Isolation Valve Closure, Scram	less than or equal to 10% Valve Closure from full open	
9) Reactor Low Water Level, Scram	greater than or equal to 11' 5" above the top of the active fuel as indicated under normal operating conditions	
10) Reactor Low-Low Water Level, Main Steam Line Isolation Valve Closure.	greater than or equal to 7' 2" above the top of the active fuel as indicated under normal operating conditions	
11) Reactor Low-Low Water Level, Core Spray Initiation	greater than or equal to 7' 2" above the top of the active fuel	
12) Reactor Low-Low Water Level, Isolation Condenser Initiation	greater than or equal to 7' 2" above the top of the active fuel with time delay less than or equal to 3 seconds	
13) Turbine Trip Scram	10 percent turbine stop valve closure from full open	
14) Generator Load Rejection Scram	Initiate upon loss of oil pressure from turbine acceleration relay	

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. Automatic protective devices have been provided in the plant design to take corrective action to prevent the safety limits from being exceeded in normal operation or operational transients caused by reasonable expected single operator error or equipment malfunction. This Specification established 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 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 rated thermal power. For slow maneuvers, 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 rated flow 61.0E6 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 point scram settings so that all thermal limits are satisfied (3, 4, 10). However, in response to expressed beliefs (5) that variation of APRM flux scram with recirculation flow is a prudent measure to ensure safe plant operation during the design confirmation phase of plant operation, the scram setting will be varied with recirculation flow. If during the power demonstration run the design analyses are confirmed with respect to nuclear behavior characteristics, the automatic flow biased scram could be replaced with a fixed scram setting.

Lowering the set point of the APRM scram would result in more margin between normal operation and the safety limit; however, lowering the set point could also result in spurious scrams. For example, there are transients which will occur during operation, such as those due to testing turbine bypass valves or pressure set point changes, which result in insignificant changes (less than 1%) in the power transferred from the cladding to the water, but for which the neutron flux rises 10-15% (3).

Calculations which include uncertainties in the heat balance show that the setting accuracy is plus or minus 2.5% in the 85-100% power range (6). A turbine trip without bypass analyzed assuming a 125% scram showed no appreciable change in results from a 120% scram analysis (3). In additon, if the errors are random, some APRM's will trip low, the net effect being no change in the transient results. Therefore, allowing for instrument calibration errors, the scram setting is adequate to prevent the safety limit from being exceeded and yet high enough to reduce the number of spurious scrams.

For slow power rises in the power range which might be produced by control rod withdrawal, the power is limited by the APRM control rod block (1), whose set point is varied automatically with recirculation flow. At conditions of rated flow or greater, the rod block is initiated at 106 percent of rated power. For the single rod withdrawal error this setting causes rod block before MCPR reaches 1.32 for 7 x 7 fuel and 1.34 for 8 x 8 fuel (13). For operation along the flow control line and at power levels less than 61% of rated the inadvertent withdrawal of a single control rod does not result in MCPR = 1.32 for 7 x 7 fuel and 1.34 for 8 x 8 fuel even assuming there is no control rod block action (7).

The safety curve of Figure 2.1.1 is based on total peaking factors of 2.74 for fuel types IIIE and IIIF: 2.80 for fuel type II; and 2.78 for 8 x 8 fuel. These curves are to be adjusted downward (by the equations shown in Specification 2.1.A.2) in the event of higher peaking factors. Also to ensure MCPR's greater than 1.32 for 7 x 7 fuel and 1.34 for 8 x 8 fuel during expected transients, neutron flux, scram and control rod block settings must be correspondingly reduced. The equations describing these setpoints

make allowance for peaking factors greater than 2.74, 2.80, or 2.78 respectively for the fuel types listed above by reducing the setpoints at rated neutron flux by the ratio of PFo to PF.

For operation in the startup mode while the reactor is at low pressure, the IRM scram setting of 15% of rated power provides 22% thermal margin between the maximum power and the safety limit, 18.3% of rated. The margin is adequate 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, cold water from sources available during startup is not much colder than that already in the system, temperature coefficients are small, and control rod patterns are constrained to be uniform by operating procedures backed up by the rod worth minimizer. 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 the IRM system would be more than adequate to assure a scram before the power could exceed the 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 Reactor Protection System is designed such that reactor pressure must be above 825 psig to successfully transfer into the RUN mode, thus assuring protection for the fuel cladding safety limit.

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 (8). 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. With the addition of the anticipatory scrams, the transient analysis for operation at 1930 MWt shows that the turbine trip with failure of the bypass system transient is the worst case transient with respect to peak pressure. Analysis of this transient shows that the relief valves limit the peak pressure well below the 1250 psig range of applicability of the fuel cladding integrity safety limit and the 1375 psig reactor coolant system pressure safety limit. 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 valves 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 MW(t), 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. For analysis purposes, the void reactivity coefficient was also pessimistically increased by 50%, i.e., a void coefficient 1.5 times normal. With the safety valves set as specified herein the maximum vessel pressure (at the bottom of the pressure vessel) would be about 1301 psig (9); maximum pressure at the lowest point in the recirculation loop is approximately 1315 psig which is 60 psi below the safety limit. The ASME B&PV Code allows a plus or minus 1% of working pressure (1250 psig) variation in the pop 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 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 valve closure scram assures the availability of neutron flux scram protection over the entire range of applicability of the fuel cladding integrity safety limit. In addition the isolation valve closure scram anticipates the pressure and flux transients which occur during normal or inadvertent isolation valve closure.

With the scrams set at 10% valve closure, there is no increase in neutron flux and the peak pressure is limited to 1110 psig (9).

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 (11).

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 or in the shutdown condition.

The turbine stop valve(s) scram anticipates the pressure, neutron flux, heat flux increase caused by the rapid closure of the turbine stop valve(s) and failure of the turbine bypass system. With a scram setting of 10% of valve closure from full open and with a failure of the turbine bypass system at 1930 MWt, the peak pressure will remain well below the first safety valve setting and no thermal limits are approached (7,10).

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 and the resultant peak pressure and MCHFR are essentially the same.

References

(1) FDSAR, Volume I, Section VII-4.2.4

(2) FDSAR, Volume I, Section I-5.6

(3) Licensing Application Amendment 28, Item III.A-12

(4) Licensing Application Amendment 32, Question 13

(5) Letters, Peter A. Morris, Director, Division of Reactor Licensing, USAEC to John E. Logan, Vice President, JCP&L Co., dated November 22, 1967 and January 9, 1968

(6) Licensing Application Amendment 11, Question V-9.

(7) Licensing Application Amendment 76, Supplement No. 1.

(8) Licensing Application Amendment 65, Section B.XI.

(9) Licensing Application Amendment 69, Section III-D-5

(10) Licensing Application Amendment 65, Section B,IV.

(11) Licensing Application Amendment 65, Section B.IX.

(12) Licensing Application Amendment 76, Supplement No. 3, Section 2.0

(13) Licensing Application Amendment 76, Supplement No. 4.

SECTION 3

LIMITING CONDITIONS FOR OPERATION

3.0 LIMITING CONDITIONS FOR OPERATION (GENERAL)

Applicability:

Applies to all Limiting Conditions for Operation.

Objective:

To perserve 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 systems 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 specified 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 and 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 compromising the effectiveness of the system. 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, cold water from sources available during startup is not much colder than that already in the system, temperature coefficients are small, and control rod patterns

are constrained to be uniform by operating procedures backed up by the rod worth minimizer. 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 begining 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 2.5E-6/hr (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 refuel 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 beneficial 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 twelve 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 psig. This trip will scram the reactor, 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 and core booster pump pressure developed, 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 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 high water level in the scram discharge volume setting is based on the design that 37 gallons of water in the scram discharge volume will permit the 137 control rods to scram with a pressure in the volume less than or equal to 65 psig. To provide further margin, one gallon of water collecting in the volume will cause an alarm. A second high level alarm is set at two gallons.

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, reactor isolation and condensor vacuum pump isolation are initiated 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 rate power. This would be indicative of the onset of fuel failures and would alert the operator to the need for appropriate actions, 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 3.2E5 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 17 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 5.0E5 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 1.0E6 CPS. This rod block is bypassed in IRM Ranges 8 and higher since a level of 5.0E5 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 Ranges and the SRM will be reading approximately 5.0E5 CPS when using IRM Range 8 and higher.

High flow in the main steamline is set at 120% of rated flow. At this setting the isolation valves close and in the event of a steamline 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 steamline 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 inputs(s) until LPRM replacement is possible. Since APRM rod block protection is not required below 61% of rated power,(1) as discussed in Sections 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.

3.2 REACTIVITY CONTROL

Applicability:

Applies tc 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 Station Engineer from 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 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.

(c) Control rod patterns shall be established so that the maximum worth of any in sequence control rod shall be less than 1.25% delta k, except:

1. During low power physics tests, and

2. During withdrawal of control rods which do not bring the reactor core to a critical condition.

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

Percent of Rod Length Inserted	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:

Percent of Rod Length Inserted	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 three source range channels have an observed count rate equal to or greater than 3 counts per second.

6. The control rod density shall be greater than 3.5 percent during power operation.

C. Standby Liquid Control System

1. The standby liquid control system shall be operable at all times when the reactor is not shutdown 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 6.9.2.

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 keff 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 keff less than 0.99, whereas the minimum condition for operation is keff less than 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.

The first cycle contains boron as a burnable neutron absorber in the temporary control curtains which results in a core reactivity characteristic which increases with exposure, goes through a maximum and then decreases (2). 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. (3) 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 (4).

The Rod Worth Minimizer (5) provides automatic supervision of conformance to the specified control rod patterns. It serves as a backup 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 withdrawl. 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 sequences are characterized by homogeneous, scattered patterns of withdrawn rods similar to that indicated in Figure 7-

14 of Reference (12). The maximum rod strengths encountered in these patterns are presented in Figure 3-9 of Reference (12) and 3-12 of Reference (13). The maximum rod strength permitted by the patterns is less than 0.01 delta k which is below strengths which could threaten the reactor coolant system. Above 10% power even single operator errors cannot result in out-of-sequence control rod worths which are sufficient to reach a peak fuel enthalphy content of 280 cal/gm; thus, requiring operation of the RWM or verification by a second licensed operator that the operator at the reactor console is following the rod program below 10% rated power is conservative.

A parametric analysis of the control rod drop accident was made in Reference (14), assuming the worst measured rod drop velocity and Technical Specification scram times, and the results indicate that a maximum in sequence rod worth of 1.25% delta k is acceptable.

The control rod system is designed to bring the reactor subcritical from a scram signal at a rate fast enough to prevent fuel damage. Figure III-1 of Amendment 69 to the FDSAR shows the control rod scram reactivity used in the transient analyses. Under these conditions, the thermal limits are never reached during the transient requiring control rod scram as presented in the FDSAR. The limiting power transient is that resulting from a turbine stop valve closure with failure of the turbine bypass system. Analysis of this transient show that the negative reactivity rates resulting from a flux scram with the average response of all operable drives in conformance with the specified limits, provide the required protection. 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 (8) 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 shutdown at all times with control rods.

Although there are many possible patterns of inoperable control rods which would meet this specification, the operator will be provided with only a limited number of predetermined patterns which allow him to continue operation with inoperable rods. The availability of allowable patterns to the operator assures that information for determining compliance with the specification is immediately available to him at the time a control rod becomes inoperable and does not require reliance on calculations at that time before compliance can be determined.

The allowable inoperable rod patterns will be determined using information obtained in the startup test program supplemented by calculations. During initial startup, the reactivity condition of the as-built core will be determined. Also, sub-critical patterns of widely separated withdrawn control rods will be observed in the control rod sequences being used. The observations, together with calculated strengths of the strongest control rods in these patterns will comprise a set of allowable separations of malfunctioning rods. During the fuel cycle, similar observations made during any cold shutdown can be used to update and/or increase the allowable patterns.

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 shutdown. 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 occured 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 (SMR) system (9) 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 1.0E-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.

A minimum of three operable SRM's is required as an added conservatism.

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 (10). 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%) (11) results in the required amount of solution being inserted into the reactor is not less than 60 minutes, and therefore, defines the maximum concentration-minimum volume requirements. The point (3737 gal, 10.3%)(11) results in the required amount of solution being injected into the reactor is 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 5^0F above the saturation temperature to guard against precipitation. The 5^0F margin is included in Figure 3.2.1. Temperature and liquid level alarms for the system are annunciated in the control room.

The allowed time out of service for a standby liquid control pumping circuit as well as other safety features is based on the following considerations. Systems are designed with redundancy to increase their availability and to provide backup if one of the components is temporarily out of service. For instance, if a system has two components, one of which is needed, plant operation may continue while a component is out of service for a reasonable time during its repair. Of course, during the out-of-service-for-repair period, the availability of the total system is somewhat

reduced. Since components are generally discovered in a failed condition only at a regularly scheduled test, the component has already been out of service for an unknown time. On the average, the failed component has been out of service for one half the test interval (tau/2). In other words, setting a test interval,tau, implies that it is acceptable to risk having the component out of service for an average period of tau/2 after a failure.

There is some combination of redundance, failure rate, and test interval that results in an acceptable low basic risk rate to operate the plant. The average risk rate including allowance for repair should be no higher than the basic risk rate at normal operation. Then if the average risk rate (including repair) is equated to the basic risk rate (during normal operation), there is a unique solution for a maximum out-of-service time, T. In other words, plant operation may continue while a component of a redundant system is out of service for repair up to a time of T, without exceeding the acceptably low risk rate of normal operation. Each combination of n systems, r of which are needed to perform the given function, has a solution for a repair time, T, as a function of test interval,tau. For the common case of two systems, one of which is needed, T =tau/3. That is, one out of two systems (if only one is needed) may be out of service for repair up to one third of the test interval. Following repair, both the standby liquid control pumping circuits are tested to demonstrate operability.

The analysis results in a good guideline for maximum time out of service for redundant systems. The analysis assumes independence of the systems and since every effort is made to design independence into redundant systems, a time out of service near the calculated T is acceptable. The calculated repair time is an "average" and the implication is that times longer than the average are allowable. However, the conservative approach is to limit all repair times to the calculated time T. In any event, repair should begin as soon as possible and proceed expeditiously, consistent with good craftsmanship.

The availability of a system is a function of its test interval. In general, the more frequent the tests, the higher the availability, because the system is not allowed to remain in a failed state for long periods of time. If one system is out of service, the overall availability of the function may be maintained by testing the remaining redundant systems on an appropriately shorter test interval. This method is particularly attractive on systems with a relatively high level of redundancy. With an appropriately short test interval, the required function availability can be maintained indefinitely while one system undergoes repair.

Only one of the two standby liquid control system pumping circuits is required to accomplish the safety function of the system. If one pumping circuit is found to be inoperable, there is no immediate threat to shutdown capability and reactor operation may continue while repairs are being made. Therefore, the time out of service for one of the pumping circuits is based on the consideration given above for one out of two system. The test

interval for pump operability is one/month (Specification 4.2). An acceptable out of service time is then determined to be

T =(tau/3) = (30 days/3) = 10 days

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.

The scram reactivity function which results from a typical end-of-cycle control rod density was presented in Reference 15 and used in the bounding transient evaluations for equilibrium 7 x 7 fuel and 8 x 8 fuel reload cores. The effects of various off-design control rod patterns on the scram reactivity function were examined in Reference 16. The results indicated that the control rod density, not distribution, is the most significant parameter. Control rod densities as low as 3.5 percent were examined with essentially the same results as for the scram reactivity function used in Reference 15. Lower control rod densities would require scram bank worth predictions in comparison to the 3.5 percent control rod density predictions to support the contention that the effects of reduced control rod density maintain adequate margins to limits in the transient analyses.

References:

(1) FDSAR, Volume I, Section III - 5.3.1.

(2) FDSAR, Volume II, Figure III - 5-11.

(3) FDSAR, Volume I, Section VI-3.

(4) FDSAR, Volume I, Section III - 5.2.1.

(5) FDSAR, Volume I, Section VII-9.

(6) FDSAR, Volume I, Section III - 5.2.2.

(7) Licensing Application Amendment 11, Question II-3.

(8) FDSAR, Volume I, Section III-5 and Volume II, Appendix B.

(9) FDSAR, Volume I, Sections VII - 4.2.2 and VII - 4.3.1.

(10) FDSAR, Volume I, Section VI-4.

(11) Licensing Application Amendment 55, Section 2.

(12) Paone, C .J., Stirn, R .C., and Wooley, J. A., Rod Drop Accident Analysis for Large Boiling Water Reactors," NEDO-10527, March 1972

(13) Paone, C. J., Stirn, R. C., and Haun, J. M., "Rod Drop Accident Analysis for Large Boiling Water Reactors, Addendum No. 2 Exposed Cores," NEDO-10527, Supplement 2, January 1973.

(14) Oyster Creek Nuclear Generating Station, Docket No. 50-219, Amendment 74, "Rod Drop Accident Analysis," May 31, 1974.

(15) Licensing Application Amendment 76, XN-74-45 (Revision 2) and XN-74-41 (Revision 2), dated January 31, 1975.

(16) Oyster Creek Licensing Submittal, "Cycle 5 Reload and Loss-of-Coolant Accident Analysis Re-Evalation" dated April 30 1975, Response 16G.

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 non-critical-- 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

Reactor coolant leakage into the primary containment from unidentified sources shall not exceed 5 gpm. In addition, the total leakage in the containment, identified and unidentified, shall not exceed 25 gpm. If these conditions cannot be met, the reactor will be placed in the cold shutdown condition.

E. Reactor Coolant Quality

1. The reactor coolant quality shall not exceed the following limits during power operation with steaming rates to the turbine-condenser of less than 100,000 pounds per hour.

conductivity	2.u mho/cm
chloride ion	0.1 ppm

2. The reactor coolant quality shall not exceed the following limits during power operation with steaming rates to the turbine-condenser of at least 100,000 pounds per hour.

conductivity	10.u mho/cm
chloride ion	1.0 ppm

3. If Specification 3.3.E.1 and 3.3.E.2 cannot be met, the reactor shall be placed in the cold shutdown condition.

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

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

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 transition (NDT) 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 (greater than 1 Mev) expected for Oyster Creek at the end of ten effective full power years of operation is 1.22E18 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 make up 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 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 drain tank unless the respective pumps are running. The sump and tank are provided with two pumps each and redundant alarms which will actuate on a predetermined pumpout rate (10). The alarms on the floor drain sump will be set at the normal, identified leakage plus 80% of the limit of 5 gpm for unidentified leakage. The alarms on the equipment drain tank will be set to alarm at a flow rate such that the total leakage (floor drain plus equipment drain) does not exceed the limit of 25 gpm for total leakage (10).

Additional qualitative information (10) is available to the operator via the monitored drywell atmospheric 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 pessure 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 pgm 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.

Chloride stress corrosion tests on stressed 304 stainless steel specimens have been reported (11). According to the data, allowable chloride concentrations could be set over an order of magnitude higher than the established limit of 1.0 ppm at the

oxygen concentraion (0.2-0.3 ppm) that will be present during power operation. Oxygen is maintained at low levels by the turbine-condenser off-gas system. Zircaloy does not exhibit similar stress corrosion failures.

Air saturated water (7 ppm oxygen) is pumped into the reactor as a result of operation of the control rod drive system. Therefore, the oxygen level in the reactor water can be higher than 0.2-0.3 ppm during startups or during periods of hot standby when the reactor is not steaming at significant powers, and a more stringent limit of 0.1 ppm chloride has been established for these periods to insure that the combination of chloride and oxygen will always be well below stress corrosion failure limits (11). At reactor steaming rates of at least 100,000 pounds per hour boiling occurs in the reactor causing deaeration of the reactor water which maintains oxygen below operating levels.

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 placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature dependent corrosion rates and thereby provide time for the cleanup system to re-establish proper water quality.

Ensuring the operational status of the primary coolant system isolation valves listed in Table 3.3.1 is intended to increase their reliability thereby reducing the potential of an intersystem loss of coolant accident.

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) Licensing Application Amendment 11, Question VI-4.

(12) Licensing Application Amendment 68, Supplement No. 6, Addendum No. 3.

(13) Licensing Application Amendment 16, Page 1.

3.4 EMERGENCY COOLING

Applicability:

Applies to the operating status of the emergency cooling systems.

Objective:

To assure operability of the emergency cooling systems.

Specification:

A. Core Spray System

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

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

3. If one core spray system loop or its core spray header delta P 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^{0}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 then 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 air operated 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, high drywell pressure and core spray booster pump discharge 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 cubic feet 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. Control Rod Drive Hydraulic System

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 36 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 the safety limit of 4'8".

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

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

$$(tau/1.71) = (30\ days/1.71) = 17.5\ days$$

Specifications 3.4.A.5 ensures that if one diesel is out of service for repair, the core spray system loop components 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 capability 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 procedures), 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 capability. For break sizes up to 0.0C2 square feet, 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 containment spray system may be made inoperable under these conditions. This prevents personnel from coming in contact with torus water.

References

(1) Licensing Application, Amendment 65, Section B.VI.6.

(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 cubic feet

b. Minimum water volume - 82,000 cubic feet

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 10°F 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 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 system) either;

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

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

c) Isolate each effected 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. <u>Reactor Building to Suppression Chamber Vacuum Breaker System</u>

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 breakers 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.A.4.a are exceeded, reactor shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 24 hours.

5. <u>Pressure Suppression Chamber - Drywell Vacuum Breakers</u>

a. When primary containment integrity 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 5.0% oxygen 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.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. <u>Shock Suppressors (Snubbers)</u>

a. During all modes of operation except cold shutdown and refuel, all safety related snubbers listed in Table 3.5.1 shall be operable except as noted 3.5.A.8.b, c and d below.

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

c. If the requirements of 3.5.A.8.a and 3.5.A.8.b cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 36 hours.

d. If a snubber is determined to be inoperable while the reactor is in the shutdown or refuel mode, the

snubber shall be made operable or replaced prior to reactor startup.

e. Snubbers may be added to safety related systems without prior License Amendment to Table 3.5.1 provided that a revision to Table 3.5.1 is included with the next License Amendment request.

9. Drywell-Suppression Chamber Differential Pressure

a. Differential pressure between the drywell and suppression chamber shall be maintained within the acceptable operating range shown on Figure 3.5.1 within 24 hours after the reactor mode selector switch is placed in the run mode. The differential pressure may be reduced to less than the range shown on Figure 3.5.1 24 hours prior to a scheduled shutdown. The differential pressure may be decreased to less than the required value for a maximum of four hours during required operability testing of the suppression chamber - drywell vacuum breakers.

b. If the differential pressure of Specification 3.5.A.9.a cannot be maintained, and the differential pressure cannot be restored within the subsequent 6 hour period, an orderly shutdown shall be initiated and the reactor shall be in the shutdown condition within the next 6 hours and the cold shutdown condition within the following 18 hours.

c. Instrumentation to measure the drywell to suppression chamber differential pressure and the torus water level shall be operable at any time the differential pressure is required to be maintained by Specification 3.5.A.9.a. Operation may continue for up to thirty days with one instrument out of service. If both differential pressure or both water level instruments are not operable, or if one instrument is out of service for more than thirty days, and such indication cannot be restored in the next 6 hours, the reactor shall be in the shutdown condition within the next 6 hours and in the cold shutdown condition within the following 18 hours.

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.

e. No operations are being performed 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 integrity is required except as specified be Specification 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). Continure 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.

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.

<u>Bases:</u> 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 the rod worth minimizer would limit the worst case rod drop accident to 1.5% k. This amount of reactivity addition is insufficient to cause fuel damage.

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 cubic feet, 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 cubic feet is reduced by not more than 5.5% metal water reaction below the capability with 82,000 cubic feet.

Experimental data includes 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 suppression 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 supression 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 chamber 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-door 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.

Conservative 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.

To preclude the possibility of starting up the reactor and operating a long period of time with a significant leak in the reactor coolant 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 oxygen 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 reactor coolant system or any other safety system or component be operable during reactor operation.

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

Examination of defective snubbers at reactor facilities and material tests performed at several laboratories (Reference 11) has shown that millable gum polyurethane deteriorates rapidly under the temperature and moisture conditions present in many snubber locations. Although molded polyurethane exhibits greater resistance to these conditions, it also may be unsuitable for application in the higher temperature environments. Data are not currently available to define precisely an upper temperature limit for the molded polyurethane. Lab tests and in-plant experience indicate that seal materials are available, primarily ethylene propylene compounds, which should give satisfactory performance under the most severe conditions expected in reactor installations.

Because snubber protection is required only during low probability events, a period of 72 hours is allowed for repairs or replacements. In case a shutdown is required, the allowance of 36 hours to reach a cold shutdown condition will permit an orderly shutdown consistent with standard operating procedures. Since plant startup should not commence with knowingly defective safety related equipment, Specification 3.5.A.8.d prohibits startup with inoperable snubbers.

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.

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.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed on August 2, 1976, which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system. The maintenance of a drywell-suppression chamber differential pressure within the range shown on Figure 3.5.1 with a suppression chamber water level corresponding to a downcomer submergence range of 3.0 to 5.3 feet will assure the intergrity of the suppression chamber when subjected to post-LOCA suppression pool hydrodynamic forces.

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 1, 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.

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:

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

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 uCi/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 of 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 uCi/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) x (3.6 E-08) x SUMi Qi Ni less than or equal to 20

for gamma air dose:

Sumi Qi Mi less than or equal to 10

Where:

SUMi 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-02) SUMi (Rii (4.8 E-08 x Qis + 2.3 E-05 x Qiv) +

(Rgi + Rvi) (5.5 E-09 x Qis + 1.0E-07 x Qiv) less than or equal to 15

Where:

SUMi 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 rems 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 "Meterology 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 x(average energy) curies per second will not result in offsite annual doses in excess of the limits specified in 10 CFR 20. The average energy 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 offsite concentration at ground level for a continuous release rate of 1 curie/second was found to be about 1.0E-9 uCi/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 MPCa of 1.0E-10 uCi/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 4 uCi/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 (1.0E-7 uCi/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 minimun 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 1.5E-12 uCi/cc per uCi/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 uCi/day release rate that will yield a discharge canal concentration not exceeding 1.0E-7 uCi/cc is approximately 6.7E4 uCi/day or about 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 fin-fish 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.

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 the 10 CFR 20 MPC for unidentified isotopes.

The main pathway to man for activity deposited in the Bay is through the comsuption 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 activity 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 uCi 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 uCi/gm.

The required use of 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 Specification limit for release of unidentified isotopes is equivalent to the guide value for design objectives given in the proposed Appendix I of 10 CFR 50.

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 converion 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).

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 1.3-11B.

(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, Calculation 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.

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 . ıctor 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 125 Volt DC motor control center DC-2.

f. 24 volt DC 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 source of power consisting of one of the following is in service and capable of feeding 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.

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 14,500 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. Since the requirements for operation of the required engineered safety features after an accident or for safe shutdown can be supplied by one diesel generator the specification requirement for 14,500 gallons of diesel fuel can operate one diesel at a load of 2640 KW for 3 days. As indicated in Amendment 32 of the Licensing Application and including the Security Systems 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.

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:

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.

Bases: 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 accommodate the reactor decay heat (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 of 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.

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 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.

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 less than or equal to 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 less than or equal to 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) 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 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% delta k, plus equivalent reactivity for the effect of any B4C 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 be 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 exits 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.

<u>Bases:</u> 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 when 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.

<u>References:</u>

(1) FDSAR, volume I, Section VII-7.2.5.

(2) FDSAR, Volume I, Section XIII-2.2.

(3) FDSAR, Volume I, Sections 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 17.2 KW/ft. (for 7 x 7 fuel) and 14.5 KW/ft. (for 8 x 8 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 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. 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 as calculated by the following equation:

LHGR less than or equal to LHGRd (1-(delta P/P)max(L/LT))

where: LHGRd = Limiting LHGR

(delta P/P) = Maximum Power Spiking Penalty
LT = Total Core Length - 144 inches
L = Axial position above bottom of core

Fuel Type	LHGRd	Delta P/P
IIIF	17.2	.033

V	14.5	.033
VB	14.5	.039

If at any time during operation it is determined by normal surveillance that the limiting value for LHGR is being exceeded, action shall be initiated 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 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.

C. Assembly Averaged Power Void Relationship

(Applicable to Fuel Type IIIF for 4-loop Operation Only)

During power operation, the assembly average void fraction and assembly power shall be such that the following relationship is satisfied:

((I-VF)/(PRxFCP)) greater than or equal to B

Where:
VF = Bundle average void fraction
PR = Assembly radial power factor
FCP = Fractional core power (relative to 1930 MWt)
B = Power-Void limit

The limiting values of "B" for fuel type IIIF is .377.

D. Minimum Critical Power Ratio (MCPR)

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

ARPM 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.)	1.64
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).	1.58
3. All B, C, and D LPRM inputs to the APRM system are operating and no APRM channels are inoperable or bypassed.	1.52

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.

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 local variations in power distribution within a fuel assembly affect the calculated peak clad temperature by less than plus or minus 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 shown in Figure 3.10.1 for Type IIIF, V and VB fuel for five loop operation and in Figure 3.10.2 for Type V and VB fuel for four loop operation 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 (2). 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 7x7 fuel . These spray heat transfer coefficients were justified in the ENC Spray Cooling Heat Transfer Test Program (3).

The maximum average planar LHGR limits shown in Figure 3.10.2 for Type IIIF fuel for four loop oepration is the result of LOCA analyses performed by Exxon Nuclear Company utilizing blowdown results obtained from a General Electric Company evaluation model in compliance with 10 CFR 50, Appendix K(1). Single failure

considerations were based on the revised Oyster Creek Single Failure Analysis submitted to the Staff on July 15, 1975.

The effect of axial power profile peak location is evaluated for the worst break size by performing a series of fuel heatup 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 2.

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 temperature 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 temperatures, power spikes were not considered in the analysis of loss-of-coolant accidents.

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 IIIF, 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 even if fuel pellet densification is postulated. The power spike penalty for Type IIIF, V and VB fuel is based on analyses presented in Facility Change Request No. 5, Facility Change Request No. 6 and Amendment 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 General Electric non-jet pump BWR ECCS model (1) utilizes an empirical correlation to determine the duration of nucleate boiling heat transfer in the early period following the postulated

pipe break. This correlation for time to dryout is found to be proportional to the ratio of assembly water volume to power. Dryout time is a significant parameter in determining the extent of nucleate and transition boiling heat transfer, and consequently the peak cladding temperature.

By maintaining reactor power and void fraction as specified in 3.10.C, dryout times at least as long as that used in the LOCA analysis will be assured. The limiting value of B in Specification 3.10.C was developed for core conditions of 100% power and 70% flow, the minimum flow that could be achieved without automatic plant trip (flow biased high neutron flux scram). Such a condition is never achieved during actual operation due to the neutron flux rod block and the inherent reactor powerflow relationship. The MAPLHGR results for fuel type IIIF shown in Figure 3.10.2 were evaluated for 102% power and 70% flow, thus the 2% conservatism for instrument uncertainty is retained in the limiting value of B. Additional conservatism is provided by the following assumptions used in determining the B limit.

1. All heat was assumed to be removed by the active channel flow. No credit was taken for heat removal by leakage flow (10% of total flow).

2. Each fuel type was assumed to be operating at full thermal power rather than the reduced power resulting from the more limiting conditions imposed by Figure 3.10.2.

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 high 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 minimum critical power ratio (MCPR) calculated for the initial conditions of the LOCA represents the thermal margin of the hot assembly to the boiling transition point. An increase in core flow from 70% would result in additional thermal margin (higher MCPR value). The conservative ECCS analysis bounds the range of permitted reactor operating conditions so long as operating MCPR's are above the values computed for the initial conditions assumed for ECCS analysis. Current plant technical specifications

(3.10.D), based upon consideration of other transients, limit the reactor operation on thermal margins substantially above the assumed ECCS conditions. The assumed initial MCPR values for the ECCS analysis are 1.37 for 7x7 and 1.40 for 8x8 fuel.

For transient operation up to the fuel cladding integrity safety limit, protection is provided against a MCPR of 1.34 for 8x8 fuel and 1.32 for 7x7 fuel. The actual steady-state operating power level provides margin to this limit by an amount corresponding to the maximum decrease in CPR resulting from single operator error or equipment malfunction from a steady-state level.

These resulting operating MCPR limits, combined with the transient analysis results, provide assurance that the fuel cladding integrity safety limit will not be violated during anticipated operating transients.

The APRM response is used to predict when the rod block occurs in the anaylsis 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 or bypassed LPRM inputs. The results indicate that the steady state MCPR required to protect the minimum transient MCPR of 1.34 at the rod block ranges from 1.5 to 1.6 depending on the APRM system status (4).

In order to provide for a limit which is considered to be bounding to future operating cycles, the variable limits have been conservatively adjusted upward to range from 1.52 to 1.64.

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.

References

(1) Oyster Creek Nuclear Generating Station, Loss-of-Coolant Accident Analysis Reevaluation and Technical Specification Change Request No. 42, Attachment I, dated December 23,1975.

(2) 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.

(3) XN-75-36 (NP)-(A), XN-75-36 (NP) Supplement 1-(A), "Spray Cooling Heat Transfers Phase 1 Test Results, ENC - 8x8 Fuel 60 and 63 Active Rods, Interim Report," October 1975.

(4) Oyster Creek Nuclear Generating Station Amendment 76 (Supplement No.4) Section 2.0, dated October 20, 1975.

3.11 INTENTIONALLY LEFT BLANK

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 Suppresion 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 period 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 nonfunction, 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 the 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 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.

Bases: 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.

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 position within 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 cold shutdown condition within 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** safety valve 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 cold shutdown condition within 24 hours.

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 cold shutdown condition within 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.

*Acoustic Monitor

**Thermocouple

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 less than 1.4g will assure alarm actuation should the adjacent safety valve lift. Minimum blowdown force considered was 30g with a maximum attenuation of 27 dB. In actuality, a safety valve lift would result in considerably larger blowdown force. The maximum attenuation of 27 dB was determined based on actual testing of a similar monitoring system installed in a similar configuration.

SECTION 4

SURVEILLANCE REQUIREMENTS

4.1 PROTECTIVE INSTRUMENTATION

Applicablilty:

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.

Bases: 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 available 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 2.5E-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, then 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 tau 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 availability by operation data. For the one-out-of-two twice logic,(2)

R=1-(SQ RT((1-A)/2)) = 1-(SQ RT((1-0.999)/2))=0.993

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

To adjust the test frequency, first 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 tau=2 months, the test interval resulting in an availability of at least 0.9999. Had no unsafe failures occurred in the same time, tau could have been extended to 3 months.

Testing once/mo is more frequent than is consistent with practicality, 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 that 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 steam line 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.

<u>References:</u>

(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 Systems, A Reliability Analysis,"
I. M. Jacobs, APED-5179, Eng. A-18, June, 1966.

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% delta k 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 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 operating 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 when equilibrium conditions are established after a refueling or major core alteration will be used as data for reactivity monitoring during subsequent power operation throughout the fuel cycle.

G. At power operating conditions, the actual control rod density will be compared with the 3.5 percent control rod density included in Specification 3.2.B.6 This comparison shall be made every equivalent full power month.

H. 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.

I. 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 60 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.

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

<u>Bases:</u> 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% delta k 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 B4C settling in all inverted tubes present in the core. The value 0.25% delta k in the expression R + 0.25% delta k 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% delta k reactivity. Observation of subcriticality in this condition assures subcriticality with not only the strongest rod fully withdrawn but at least an R + 0.25% delta k 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 test 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.

The control rod inventory check provides detection of reactivity anomalies, and additional verification of control rod position at a frequency which is compatible with the time and power varying parameters being checked.

<u>References</u>

(1) FDSAR, Volume II, Figure III-5-11.

(2) FDSAR, Volume I, Section VI-3.

(3) FDSAR, Volume I, Section III-5 and Volume II,

Appendix B.

(4) FDSAR, 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 [illegible].3.1.

B. Non-destructive examinations shall be made on the components as specified in Table 4.3.1. Any indication of a defect shall be investigated and evaluated.

C. 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. The requirements of Specification 3.3.A shall be met during the test.

D. Each replacement safety valve or valve that has been repaired shall be bench checked for the proper set point. A minimum of 5 of the valves shall be bench checked or replaced with a bench checked valve each refueling outage such that all valves are checked in three successive refueling outages, to insure set points are as follows:

Number of Valves	Set Point (psig)
4	1212 = 12
4	1221 = 12
4	1230 = 12
4	1239 = 12

E. 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.

F. Periodic leakage testing (a) on each valve listed in Table 4.3.2 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 preceeding 9 months, and prior to returning the valve to service after maintenance, repair or replacement work is performed.

(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.

Bases: Numerous data are available relating integrated flux and the change in Nil-Ductility 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 1.0E17 nvt is reached, the confirmation can be made long before an NDTT shift would occur.

Prior to operation the reactor coolant system will be free of gross defects and the facility has been designed such that gross defects should not occur throughout life; however, to determine the status of the coolant system to ensure that gross defects are not developing this surveillance program was developed. This inspection will reveal problem areas should they occur before a leak develops. In addition, extensive visual inspection for leaks will be made on critical systems. The inspection period is based on the observed rate of growth of defects from fatigue studies sponsored by the AEC. These studies show that it requires thousands of stress cycles, at stresses beyond any conceived in a reactor system to propagate a crack and it is thus concluded that the frequency is adequate. The access provisions for in-service inspection has been compared with the access requirements of the proposed N-45 Code for In-Service Inspection of Nuclear Reactor Coolant Systems. The degree of access required by N-45 is not generally available, however, volumetric inspection of accessable areas has been proposed. It is considered appropriate to evaluate the results obtained from compliance with this Technical Specification and the state of the art before establishing a long term inspection program.

Experience in safety valve operation shows that a check of approximately 1/3 of the safety valves per year is adequate to detect failures or deterioration. The tolerance value is specified in Section I of the ASME Code at plus or minus 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.E are not exceeded. The chloride ion content will not change rapidly over a period of several days; therefore, the sampling frequency is adequate.

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 delta P 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

D. Emergency Service Water System

1. Pump operability	Once/month. Also after major maintenance and prior to startup following refueling outage.
2. Automatic actuation test	Every 3 months

E. Control Rod Drive 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 stoked 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 shall be performed prior to initial plant operation at the test pressures of 35 psig (Pp) and the test pressure (Pt) 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 approximately 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 Pt 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 quanity 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 (Pp).

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

Lt (20) = 1.0 Lm (20)/Lm (35)

or

Lt (20) = 1.0 SQ RT ((Pt(20))/(Pt(35)))

3. The allowable operational leak rate, Lto (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 Lt (20).

C. <u>Corrective Action</u>

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 Pt and deducted from the integrated leak rate measurement, yield a leakage rate value not in excess of the allowable operational leak rate Lto(20).

D <u>Frequency</u>

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 Lt(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. <u>Local Leak Rate Tests</u>

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 shall 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 Lt 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% Lto (20)
b.	Testable penetrations and isolation valves	30% Lto (20)
c.	Primary containment air purge penetrations and reactor building to torus vacuum relief valves	50% Lto (20)
d.	Any one penetration or isolation valve	5% Lto (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 test. 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	greater or equal to 3 sec. and less than or equal to 10 sec.
Isolation condenser isolation valves	less than or equal to 60 sec.

Cleanup system isolation valves	less than or equal to 60 sec.
Cleanup auxiliary pumps system isolation valves	less than or equal to 60 sec.
Shutdown system isolation valves	less than or equal to 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. <u>Reactor Building to Suppression Chamber Vacuum Breakers</u>

a. The reactor building to suppression chamber vacuum breakers and associated instrumention, 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.4.a. The air-operated vacuum breaker instrumentation shall be calibrated during each refueling outage.

5. <u>Pressure Suppression Chamber - Drywell Vacuum Breakers</u>

a. <u>Periodic Operability Tests</u>

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 chamber - 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 greater than or equal to 99% of a halogenated hydrocarbon refrigerant test gas and the HEPA filters remove greater than or equal to 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 greater than or equal to 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 absorbers 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 Fire-bar D shall be placed inside the drywell near the reactor core midplant 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.

5. Drywell-Suppression Chamber Differential Pressure

a. The pressure differential between the drywell and suppression chamber shall be recorded at least once per shift when the primary containment is required to be inerted by Specification 3.5.A.9.a.

b. Instrumentation to measure the drywell to suppression chamber differential pressure and suppression chamber water level shall be calibrated once every 6 months.

Q. Shock Suppressors (Snubbers)

1. All hydraulic snubbers listed in Table 3.5.1 whose seal material has been demonstrated by operating experience, lab testing or analysis to be compatable with the operating environment shall be visually inspected. This inspection

shall include, but not necessarily be limited to, inspection of hydraulic fluid reservoir, fluid connections, and linkage connections to the piping and anchor to verify snubber operability in accordance with the following schedule:

Number of Snubbers Found Inoperable During Inspection or During Inspection Interval	Next Required Inspection Interval
0	18 months plus or minus 25%
1	12 months plus or minus 25%
2	6 months plus or minus 25%
3, 4	124 days plus or minus 25%
5, 6, 7	62 days plus or minus 25%
greater than or equal to 8	31 days plus or minus 25%

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

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

2. The initial inspection shall be performed within 12 months from the date of issuance of these specifications. For the purpose of entering the schedule into Specification 4.5.Q.1, it shall be assumed that the facility had been on a 12 month inspection schedule.

3. All hydraulic snubbers whose seal materials have not been demonstrated to be compatible with the operating environment shall be visually inspected for operability every 31 days except when in the shutdown or refuel mode.

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

<u>Bases:</u> 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 adsorption 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% for halogens, 95% for particulates, and assuming the fission products 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 the 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 at 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 calulations.

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 a 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 square inches (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 1.25^0. 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 chamber. 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 suppresion 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 extremely 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 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.

*Trade name of E. I. duPont de Nemours & Company

**D R Muhbaier, "In Place Nondestructive Leak Test for Iodine Absorbers, Proceedings of the 9th AEC Air Cleaning Conf, USAEC Rept Conf-660904, 1966

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. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (normal time less 25%) may not be used to lengthen the inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

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

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

To further increase the assurance of snubber reliability, functional tests should be performed once each refueling cycle. These tests will include stroking of the snubbers to verify proper piston movement, lock-up and bleed. Ten percent or ten snubbers, whichever is less, represents an adequate sample for such tests. Observed failures of these samples should require testing of additional units. Snubbers in high radiation areas or those especially difficult to remove (see Table 3.5.1) need not be selected for functional tests provided operability was previously verified. Snubbers of rated capacity greater than 50,000 lb. are exempt from the functional testing requirements because of the inpracticability of testing such large 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.

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 requrired.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitering 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 leakings 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.

<u>References</u>

(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.

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 (greater than 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 a gross ratio of long-lived (greater than 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% of the maximum release rate given in specification 3.6.A(1) and the average daily gross activity release rate increased by 50% 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% 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 activiy and the results recorded. Should there be any unexplained significant changes in gross alpha, beta or gamma activity from previous 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 identified 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% of the mixture MPC, a new isotopic analysis shall be performed and recorded.

(3) Environmental Program

The environmental program described in Section B.11.6 of Amendment 65 to the Application for a 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.

Bases: 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 pushbutton 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.F are not exceeded.

The isotopic analyses of the weekly or 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:

Minimum D.F. = C1/MPC1 + C2/MPC2 + ... + Cn/MPCn

Where:

C1 = Concentration of isotope 1, etc.

MPC1 = MPC of isotope 1 from Appendix B, Table II, Column 2, 10 CFR 20, etc.

Cn = 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:

Mixture MPC =(Gross concentration/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.

<u>Reference</u>

(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 performed 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 plus or minus 1 volt and to reset at 125 plus or minus 1 volt (Diesel; 112 volts plus or minus 1 volt).

Bases: 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 temperatures check	Once/shift

Bases: 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 judgement 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 therafter, 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 removed and that the control rod is fully inserted.

Bases: 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 judgement 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. Assembly Averaged Power-Void Relationship (Applicable to Fuel Type IIIF for 4-Loop Operation Only)

Compliance with the Power-Void Relationship in Section 3.10 will be verified at least once during a startup between 50% and 70% power, when steady state power operation is attained and at least every 72 hours thereafter during power operation.

D. Minimum Critical Power Ratio (MCPR).

MCPR and APRM status 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 Power-Void Relationship is verified between 50% and 70% power during a startup. This single verification during startup is acceptable since operating experience has shown that even under the most extreme void conditions encountered at lower power levels, the relationship is not violated. Additionally reduced power operation involves less stored heat in the core and lower decay heat rates which would add further margin to limiting peak clad temperatures in the event of a LOCA.

Verification when steady state power operation is attained and every 72 hours thereafter is appropriate since once steady state conditions are achieved, the void fraction, radial peaking factor, and power level that combine to form the relationship are unlikely to change so rapidly to result in a significant change during that period.

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 hour 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 hour 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 section 3.10. Consequently, monitoring of these quantities below 25% of 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 microcurie of radioactive material on the test sample. If the test reveals the presence of 0.005 microcurie or more of removeable 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 transfer or 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.

Specifications:

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,

(3) The pilot cell specific gravity, corrected to 77^{0}F, 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,

(2) The specific gravity, corrected to 77^{0}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 anti-corrosion 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 (CO2) 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. <u>Halon Systems</u>

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, actuate 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. <u>Yard Fire Hydrants and Hydrant Hose Houses</u>

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.

Bases: 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.

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

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 10 CFR 100.3. 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 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 cubic feet and is designed to conform to ASME Boiler and Pressure Vessel Code Section VIII for an internal pressure of 62 psig at $175^{\circ}F$ and an external pressure of 2 psig at $150^{\circ}F$ to $205^{\circ}F$. The absorption chamber shall have a total volume of approximately 210,000 cubic feet. It is designed to conform to ASME Boiler and Pressure Vessel Code Section VIII for an internal pressure of 35 psig at $150^{\circ}F$ and an external pressure of 1 psig at $150^{\circ}F$.

B. Penetrations added to the primary containment shall be designed in accordance with standards set forth in Section V-1.5 of the Facility 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 Keff 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 infinity less than or equal to 0.95.

C. The maximum U-235 loading in grams of U-235 per axial centimeter of fuel shall not exceed 15.6 gms U-235/cm.

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 30 ton spent fuel shipping cask shall not be lifted more than 6 inches above the top plate of the cask drop protection system. Vertical limit switches shall be operable to assure the 6 inch vertical limit is met when the cask is above the top plate.

F. The temperature of the water in the spent fuel storage pool, measured at or near the surface, shall not exceed 125°F.

Bases: The specification of K inifinity less than or equal to 0.95 and the maximum U-235 loading of less than or equal to 15.6 gm U-235/cm per axial centimeter for fuel in the spent fuel storage facility assures an ample margin from criticality. Conservative assumptions and allowance for tolerance, void effects, calculational uncertainties, pool temperature effects, etc. have been considered in the derivation of these limits (1,2). Note that the 15.6 gm U-235/cm is equivalent to a 3 w/o enrichment.(7)

The 15.6 gm U-235/cm is the limit of U-235 at any plane through the assembly perpendiculer to the length of the assembly. It is to assure that possible non-uniform enrichments along the length of fuel rods cannot lead to a critical condition.

The effects of a dropped fuel bundle onto stored fuel in the spent fuel storage facility has 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 (3,4,5) and that dropped waste cans will not damage the pool liner.

The elevation limit 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 (6) 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 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 temperature 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 $65^{0}F$ is the appropriate minimum air temperature. The spent fuel pool water temperature will alarm in the control room before the water temperature reaches $120^{0}F$.

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 (9). The fuel pool floor framing was found to be capable of withstanding the maximum postulated thermal transient for at least 15 hours without exceeding ACI Code requirements. The floor framing was also found to be capable of withstanding the steady state thermal gradient conditions with the pool water temperature at $150^{0}F$ without exceeding ACI Code requirements. Studies show that the critical elements of the walls indentified in the analyses of (8) are capable of withstanding eight hours of the maximum postulated thermal transient without exceeding ACI Code requirements and they are judged able to continue full functional capability for at least 10 hours under these conditions (9). The walls are also capable of operation at a steady state condition with the pool water temperature at $140^{0}F$ (9).

Since the cooled fuel pool water returns to the pool at the bottom of the pool and the heated water is removed from the surface of the pool, temperature measurement at the pool surface is appropriate to estimate the pool bulk temperature.

References

(1) Amendment 78 to the Facility Description and Safety Analysis Report(Section 3)

(2) Supplement 1 to Amendment No. 78 to the Facility Description and Safety Analysis Report (Questions 14-20, 24, 25)

(3) Amendment 78 to the FDSAR (Section 7)

(4) Supplement No. 1 to Amendment 78 to the FDSAR (Question 12)

(5) Supplement No. 1 to Amendment 78 of the FDSAR (Question 40)

(6) Supplement No. 1 to Amendment 68 of the FDSAR

(7) Supplement No. 1 to Amendment 78 of the FDSAR (Question 18)

(8) Addendum No. 2 to Supplement No. 1 to Amendment 78 of the FDSAR (Question 5 and 10).

(9) Revision No. 1 to Addendum 2 to Supplement No. 1 to Amendment 78 of the FDSAR (Question 5 and 10).

Section 6

ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILTY

6.1.1

The Vice President & Director shall be responsible for overall facility operation. Those responsibilites 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 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 times. The Fire Brigade shall not include the minimum shift crew necessary for safe shutdown of the unit 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.

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 Operators'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.

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 Core Engineering

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 years's nuclear power plant experience.

Manager Plant Materiel

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 & 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.

Manager Plant Engineering

The engineer 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.

Manager/Deputy Radiological Controls (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.

Chemistry Manager

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.

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 leat 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 Manager/Deputy Radiological Controls, 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 perform 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 SAFETY REVIEW AND AUDIT

The Vice President & Director and three organizational units, the Plant Operations Review Committe (PORC), the Independent Safety Review Groups (ISRG) and the General Office Review Board (GORB) function to accomplish nuclear safety review and audit of the Oyster Creek Station.

6.5.1 VICE PRESIDENT & DIRECTOR

6.5.1.1 FUNCTION

The Vice President & Director shall ensure that:

a. All proposed changes to equipment or systems have been evaluated to determine if they constitute a change to the facility or procedures as described in the Safety Analysis Report.

b. All proposed changes to equipment or systems that constitute a change of the facility or procedures as described in the Safety Analysis Report have been evaluated to determine whether they involve an unreviewed safety question as defined in paragraph 50.59, Part 50, Title 10, Code of Federal Regulations.

c. All proposed tests and experiments have been evaluated to determine whether or not they involve unreviewed safety questions as defined in paragraph 50.59, Part 50, Title 10, Code of Federal Regulations.

6.5.1.2 AUTHORITY

The Vice President & Director has the authority to:

a. Make a determination as to whether proposed changes to equipment, or systems involve a change to the procedures or facility as described in the Safety Analysis Report.

b. Make a determination as to whether or not proposed tests or experiments and changes to equipment or systems involve an unreviewed safety question.

c. Direct the Plant Operations Review Committee to review safety evalutions of proposed changes to equipment or systems and safety evaluations of proposed tests and experiments to determine whether or not such changes, tests or experiments involve unreviewed safety questions.

NOTE: Each determination that a proposed test, experiment, or change to a system or equipment that does not involve an unreviewed safety question shall be reviewed by the Independent Safety Review Groups to verify that the determination was correct. This review shall be documented but is not a pre-requisite of the test, experiment, or change to a system or equipment.

6.5.1.3 RECORDS

Any safety evaluations done in accordance with 6.5.1.1 (b) and (c) and any determinations made pursuant to 6.5.1.2.(b) must be documented. Copies of these determinations shall be provided to the ISRG Coordinator and the Chairman of the General Office Review Board. Records of all tests and experiments performed and all changes to equipment or systems made under the provisions of 10 CFR Part 50.59 shall also be maintained at the station.

6.5.2 PLANT OPERATIONS REVIEW COMMITTEE (PORC)

6.5.2.1 FUNCTION

The PORC shall function to advise the Vice President & Director.

6.5.2.2 COMPOSITION

The PORC shall consist of the following plant personnel:

Safety Review Manager
Plant Operations Director
Plant Engineering Director
Manager Plant Materiel
Manager/Deputy Radiological Controls.

The Vice President & Director shall designate the Chairman and Vice-Chairman from among the PORC members.

6.5.2.3 ALTERNATES

Alternate members shall be appointed in writing by the PORC Chairman and will have the type of experience and training required of regular members. However, they need not have the extensive longevity in the designated fields as long as in the opinion of the Chairman, their experience and judgement are adequate.

6.5.2.4 MEETING FREQUENCY

The PORC shall meet at least once per calendar month as convened by the PORC Chairman or the Vice President & Director.

6.5.2.5 QUORUM

A quorum of the PORC shall consist of the Chairman or Vice Chairman and three members/alternates. No more than two alternate members shall be counted in establishing a quorum.

6.5.2.6 RESPONSIBILITIES

The responsibilities of the PORC are included in Table 6.5.1.

6.5.2.7 AUTHORITY

a. The PORC shall be advisory to the Vice President & Director. Nothing herein shall relieve the Vice President & Director of his responsibility or authority for overall safety operations including taking immediate emergency action. Determinations on Items a and b of Table 6.5.1 shall be documented in writing.

6.5.2.8 RECORDS

The PORC shall maintain written minutes of each meeting and copies of minutes and determinations shall be provided to the Vice President & Director, ISRG Coordinator, and the Chairman of the GORB.

6.5.3 INDEPENDENT SAFETY REVIEW GROUPS (ISRG)

6.5.3.1 FUNCTION AND COMPOSITION

The ISRG shall function under the direction of an ISRG Coordinator, who shall be appointed by the Vice President & Director to provide safety reviews. The ISRG Coordinator shall have available the competence to review problems in the following area:

a. Nuclear Power Plant Operations
b. Nuclear Engineering
c. Chemistry and Radiochemistry
d. Metallurgy
e. Instrumentation and Control
f. Radiological Safety
g. Mechanical and Electrical Engineering
h. Quality Assurance practices

The Coordinator shall establish, as needed, groups of two or more individuals with the expertise required for each topic to be reviewed.

6.5.3.2 CONSULTANTS

Consultants shall be utilized as necessary to supplement the expertise available in the GPU Nuclear Corporation.

6.5.3.3 RESPONSIBILITIES

The specific responsibility to ensure accomplishment of the independent safety review of the Vice President & Director determinations involving safety questions is assigned to the ISRG Coordinator and is accomplished by utilizing, as necessry, the full scope of expertise available in the GPU Nuclear Corporation staff, consultants, contractors and vendors as appropriate. Table 6.5.1 defines the specific independent safety review responsibilities.

6.5.3.4 AUTHORITY

The ISRG advises the Vice President & Director. It has the authority to conduct reviews and investigations, which will be documented.

6.5.3.5 AUDITS

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 operation to all provisions contained within the Technical Specifications and applicable license conditions at least once per year.

b. The performance training and qualifications of the entire facility staff at least once per year.

c. The results of all actions taken to correct deficiences 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 every 12 months.

e. The Facility Security Plan and implementing procedures every 12 months.

f. Any area of facility operation considered appropriate by the GORB or the Vice President & Director.

6.5.3.6 RECORDS

Written documentation of all independent safety reviews and investigations will be forwarded to the Vice President & Director and the Chairman of the General Office Review Board. In addition, any reportable occurrance or item involving an unreviewed safety question which is identified by the ISRG will be documented and reported immediately to the above mentioned persons.

The audit findings which result from all audits conducted in accordance with Section 6.5.3.5 shall be documented and reported to the above mentioned persons within 30 days after completing the audit. Reports documenting corrective action will receive the same distribution and they will also be forwarded to the ISRG Coordinator.

6.5.4 GENERAL OFFICE REVIEW BOARD (GORB)

6.5.4.1 FUNCTION

The technical and administrative function of the GORB is to provide independent review of major safety issues, to foresee potentially significant nuclear and radiation safety problems, and to advise the Office of the President on these matters.

6.5.4.2 COMPOSITION

Members of the General Office Review Board shall possess extensive experience in their individual specialties and collectively have the competence in the following areas:

a. Nuclear Power Plant Operations
b. Nuclear Engineering
c. Chemistry and Radiochemistry
d. Metallurgy
e. Instrumentation and Control
f. Radiological Safety
g. Mechanical and Electrical Engineering

The Chairman and Vice Chairman shall be appointed by the Office of the President. (Neither shall be an individual with line responsibility for operation of the plant).

The Chairman shall designate a minimum of six additional members. No more than a minority of the Board shall have line responsibility for operation of Oyster Creek Nuclear Generating Station.

6.5.4.3. <u>ALTERNATES</u>

Alternate members shall be appointed in writing by the GORB Chairman and will have the type of experience and training required of regular members, however, they need not have the extensive longevity in the designated fields as long as, in the opinion of the Chairman, their experience and judgement are adequate.

6.5.4.4 <u>MEETING FREQUENCY</u>

The GORB shall meet at least semi-annually and any time at the request of the Chairman or the Office of the President.

6.5.4.5 <u>QUORUM</u>

A quorum shall consist of the Chairman or Vice Chairman and three members/alternates. No more than one alternate member shall be counted when establishing a quorum and no more than a minority of the quorum shall hold line responsibility for operations of the Oyster Creek Station.

6.5.4.6 <u>RESPONSIBILITIES</u>

a. The primary responsibility of the GORB is to foresee potentially significant nuclear and radiation safety problems and to recommend to the Office of the President how they may be avoided or mitigated.

b. Carry out the specific independent safety review responsibilities listed in Table 6.5.1.

6.5.4.7 <u>AUTHORITY</u>

The GORB shall be advisory to the Office of the President and shall have the authority to conduct reviews, audits, and investigations requrested by the Office of the President or as deemed necessary by the GORB in the fulfillment of its responsibilities.

6.5.4.8 <u>AUDITS</u>

The report of the management review of the QA Plan, initiated by the Vice President & Director in accordance with the Operational Quality Assurance Plan, shall be reviewed by the GORB with respect to safety and administrative safety issues.

6.5.4.9 <u>RECORDS</u>

Minutes of each GORB meeting shall be recorded and approved by the GORB Chairman. Copies of approved minutes will be forwarded to the Office of the President, Vice President & Director, PORC Chairman, and others designated by the GORB Chairman. GORB recommendations to the Office of the President will be documented in a letter from the GORB Chairman to the Office of the President. Included with each letter will be any dissenting opinions of members of the Board.

6.6 REPORTABLE OCCURRENCE ACTION

6.6.1

The following actions shall be taken in the event of a Reportable Occurrence:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Specification 6.9.

b. Each Reportable Occurrence Report submitted to the Commission shall be reviewed by the Plant Operations Review Committee and submitted to the ISRG Coordinator and the Vice President & Director.

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 & Director.

c. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the Plant Operations Review Committee and submitted to the Vice President & Director. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components systems or structures, and (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. It shall also be submitted to the ISRG Coordinator.

6.8 PROCEDURES

6.8.1

Written procedures shall be established, implemented, and maintained that meet or exceed the requirements, of Section 5.1 and 5.3 of American National Standard N18.7-1976 and Appendix "A" of the Nuclear Regulatory Commission's Regulatory Guide 1.33-1972 except 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 by the Plant Operations Review Committee and approved by the Vice President & Director 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 the supervisory staff, at least one of whom possesses a Senior Reactor Operator License.

c. The change is documented, subsequently reviewed by the Plant Operations Review Committee and approved by the Vice President & Director as specified in the Administrative Procedures.

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 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 unit 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,
other personnel (including contractors) receiving
g ter than 100 mrem/year and their associated man rem
ording to work and job functions (this tabulation
he requirements of 10 CFR 20.407), e.g., reactor
s l 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 OCCURANCES

Reporting occurrences, including corrective actions and measures to prevent reoccurrences, shall be reported to the NRC. Supplemental reports may be required to fully describe final resolution of occurrance. In case of corrected or supplemental reports, a licensee event report shall be completed and reference shall be made to the original report date.

a. Prompt Notification With Written Followup. The types of events listed below shall be reported as expeditiously as possible, but within 24 hours by telephone and confirmed by telegraph, mailgram, or facsimile transmission to the Director of the appropriate Regional Office, or his designate no later than the first working day following the event, with a written followup report within two weeks. The written followup report shall include, as a minimum, a completed copy of a licensee event report form. Information provided on the licensee event report form shall be supplemented, as needed, by additional narrative material to provide a complete explanation of the circumstances surrounding the event.

(1) Failure of the reactor protection system or other systems subject to limiting safety system settings to initiate the required protective function by the time a monitored parameter reaches the setpoint specified as the limiting system setting in the technical specifications or failure to complete the required protective function.

NOTE: Instrument drift discovered as a result of testing need not be reported under this item but may be reportable under items 2.a(5), 2.a(6), or 2.b(1) below.

(2) Operation of the unit or affected systems when any parameter or operation subject to a limiting condition is less conservative than the least conservative aspect of the limiting condition for operation established in the technical specifications.

NOTE: If specified action is taken when a system is found to be operating between the most conservative and the least conservative aspects of a limiting condition for operation listed in the technical specifications, the limiting condition for operation is not considered

to have been violated and need not be reported under this item, but it may be reportable under item 2.b(2) below.

(3) Abnormal degradation discovered in fuel cladding, reactor coolant pressure boundary, or primary containment.

NOTE: Leakage of valve packing or gaskets within the limits for identified leakage set forth in technical specifications need not be reported under this item.

(4) Reactivity anormalies, involving disagreement with the predicted value of reactivity balance under steady state conditions during power operation, greater than or equal to 1% delta k/k; a calculated reactivity balance indicating a shutdown margin less conservative than specified in the technical specifications; short-term reactivity increases that correspond to a reactor period of less than 5 seconds or, if sub-critical, an unplanned reactivity insertion of more than 0.5% delta k/k or occurrence of any unplanned criticality.

(5) Failure or malfunction of one or more components which prevents or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the SAR.

(6) Personnel error or procedural inadequacy which prevents or could prevent, by itself, the fulfillment of the functional requirements of systems required to cope with accidents analyzed in the SAR.

NOTE: For items 2.a(5) and 2.a(6) reduced redundancy that does not result in a loss of system function need not be reported under this section but may be reportable under items 2.b(2) and 2.b(3) below.

(7) Conditions arising from natural or man-made events that, as a direct result of the event require plant shutdown, operation of safety systems, or other protective measures required by technical specifications.

(8) Errors discovered in the transient or accident analysis or in methods used for such analysis as described in the safety report or in the bases for the technical specifications that has or could have permitted reactor operation in a manner less conservative than assumed in the analysis.

(9) Performance of structures, systems, or components that requires remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analysis in the safety analysis report or technical specifications bases; or discovery during plant life of conditions not specifically considered in the safety analysis report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition.

NOTE: This item is not intended to provide for the reporting of potentially generic problems.

b. <u>Thirty Day Written Reports</u>. The reportable occurrences discussed below shall be the subject of written reports to the Director of the appropriate Regional Office within thirty days of occurrence of the event. The written report shall include, as a minimum, a complete copy of a licensee event report form. Information provided on the licensee event form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

(1) Reactor protection system or engineered safety feature instrument settings which are found to be less conservative than those established by the technical specifications but which do not prevent the fulfillment of the functional requirements of affected systems.

(2) Conditions leading to operation in a degraded mode permitted by a limiting condition for operation or plant shutdown required by a limiting condition for operation.

NOTE: Routine surveillance testing, instrument calibration, or preventive maintenance which require system configurations as described in items 2.b(1) and 2.b(2) need not be reported except where test results themselves reveal a degraded mode as described above.

(3) Observed inadequacies in the implementation of administrative or procedural controls which threaten to cause reduction of degree of redundance provided in reactor protection systems or engineered safety feature systems.

(4) Abnormal degradation of systems other than those specified in item 2.a(3) above designed to contain radioactive material resulting from the fission process.

NOTE: Sealed sources or calibration sources are not included under this item. Leakage of valve packing or gaskets within the limits for identified leakage set forth in technical specifications need not be reported under this item.

6.9.3 <u>UNIQUE REPORTING REQUIREMENTS</u>

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 analysis performed.

   d. Percent of technical specification limit.

2. Iodine Releases

   a. Total iodine radioactivity (in curies) by nuclide releases based on representative isotopic analysis performed.

   b. Percent of technical specification limit for I-131 released.

3. Particulate Releases

   a. Total gross radioactivity (Beta, Gamma) 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 (Beta, Gamma) released (in curies) excluding tritium and average concentration released to the unrestricted area.

   b. The maximum concentration of gross radioactivity (Beta, Gamma) 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 analysis 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 removeable contamination.

(e). Inoperable Fire Protection Equipment (3.12)

(f). 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.

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 principle 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 meetings of the Plant Operations Review Committee and the General Office Review Board.

k. Records for Environmental Qualification which are covered under the provisions of paragraph 6.14.

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 shall 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 made 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

Specifications 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.

* Areas requiring personnel access for establishing hot shutdown conditions.

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 Operable 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	less than or = to 2 psig		X(u)	X(u)	X	2	2	
4. Low Reactor Water Level	**		X	X	X	2	2	
5. High Water Level in Scram Discharge Volume	less than or = to 37 gal.		X(a)	X(z)	X(z)	2	2	
6. Low Condenser Vacuum	greater than or = to 23" Hg		X(b)	X(b)	X	2	2	
7. High Radiation in Main Steamline Tunnel	less than or = to 10 x normal background		X(s)	X	X	2	2	
8. Average Power Range Monitor (APRM)	**		X(c,s)	X(c)	X(c)	2	3	
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	

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 Operable Instrument Channels Per Operable Trip Systems	Action Required*
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	less than or = to 120% rated	X(s)	X(s)	X	X	2	2	
3. High Flow in Main Steamline B	less than or = to 120% rated	X(s)	X(s)	X	X	2	2	
4. High Temperature in Main Steamline Tunnel	less than or = to Ambient at Power + 50 F	X(s)	X(s)	X	X	2	2	
5. Low Pressure In Main Steamline	**				X	2	2	
6. High Radiation in Main Steam Tunnel	less than or = to 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 Level	greater than or = to 7'2" above top of active fuel	X(s)	X(s)	X	X	2	2	
D. Core Spray								Consider the respective core spray loop inoperable, & comply with Spec. 3.4
1. Low-Low Reactor Water Level	**	X(t)	X(t)	X(t)	X	2	2	
2. High Drywell Pressure	less than or = to 2 psig	X(t)	X(t)	X(t)	X	2(k)	2(k)	
3. Low Reactor Pressure (valve permissive)	greater than or = to 285 psig	X(t)	X(t)	X(t)	X	2	2	

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 Operable Instrument Channels Per Operable Trip Systems	Action Required*
E. Containment Spray								Consider the containment spray loop inoperable and comply with Spec. 3.4
1. High Drywell Pressure	less than or = to 2 psig	X(u)	X(u)	X(u)	X	2(k)	2(k)	
2. Low-Low Reactor Water Level	greater than or = to 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	less than or = to 2 psig	X(u)	X(u)	X(u)	X	2(k)	2(k)	
2. Low-Low Reactor Water Level	greater than or = to 7'2" above top of active fuel	X(u)	X(u)	X(u)	X	2	2	
G. Automatic Depressurization								See note h
1. High Drywell Pressure	less than or = to 2 psig	X(v)	X(v)	X(v)	X	2(k)	2(k)	
2. Low-Low-Low Reactor Water Level	greater than or = to 4'8" above top of active fuel	X(v)	X(v)	X(v)	X	2	2	
3. AC Voltage	NA			X(v)	X	2	2	Prevent auto depressurization on loss of AC power. See note i
H. Isolation Condenser Isolation								Isolate affected isolation condenser, comply with Spec. 3.8
1. High Flow Steam line	less than or = to 20 psi differential pressure	X(s)	X(s)	X	X	2	2	
2. High Flow Condensate Line	less than or = to 27" differential water	X(s)	X(s)	X	X	2	2	

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 Operable Instrument Channels Per Operable Trip Systems	Action Required*
I. Offgas System Isolation								Isolate reactor or trip the inoperable instrument channel
1. High Radiation in Offgas Line (e)	less than or = to 10 x stack Release limit (See 3.6-A.1)	X(s)	X(s)	X	X	1	2	
J. Reactor Building Isolation and Standby Gas Treatment System Initiation								Isolate Reactor Bldg. & Initiate Standby Gas Treatment System, or Manual Surv 'llance for not more than 24 hours (total for all instruments under J) in any 30-day period
1. High Radiation Reactor Building Operation Floor	less than or = to 100 Mr/Hr.	X(w)	X(w)		X	1	1	
2. Reactor Bldg. Ventilation Exhaust	less than or = to 17 Mr/Hr	X(w)	X(w)	X	X	1	1	
3. High Drywell Pressure	less than or = to 2 psig	X(u)	X(u)	X	X	1(k)	2(k)	
4. Low-Low Reactor Water Level	greater than or = to 7'2" above top of active fuel	X	X	X	X	1	2	
K. Rod Block								No control rod withdrawals permitted
1. SRM Upscale	less than or = to 5.0 E5 cps		X	X(1)		1	3(y)	
2. SRM Downscale	greater than or = to 100 cps (f)		X	X(1)		1	3(y)	
3. IRM Downscale	greater than or = to 5/125 fullscale(g)		X	X		2	3	
4. APRM Upscale	**		X(s)	X	X	2	3(c)	
5. APRM Downscale	greater than or = to 2/150 fullscale				X	2	3(c)	
6. IRM Upscale	less than or = to		X	X		2	3	

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 Operable Instrument Channels Per Operable Trip Systems	Action Required*
	108/125 fullscale							
7. Scram Discharge Volume a) Water level high	less than or = to 18 gallons		X(z)	X(z)	X(z)	1	1	
L. Condenser Vacuum Pump Isolation								Insert control rods
1. High Radiation in Main Steam Tunnel	less than or = to 10 x Normal Background		During Startup and Run when vacuum pump is operating			2	2	
M. Diesel Generator Load Sequence Timers	Time delay after energiz. of relay							
1. Containment Spray Pump	40 sec plus or minus 15%	X	X	X	X	2(m)	1(n)	Consider containment spray loop inoperable and comply with Spec. 3.4.C (See note q).
2. CRD Pump	60 sec plus or minus 15%	X	X	X	X	2(m)	1(n)	Consider the pump inoperable and comply with Spec. 3.4.D (See Note q.)
3. Emerg. Service Water Pump (r)	45 sec. plus or minus 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)	(SK1A) 120 sec (SK2A) plus or minus %15 10 sec (SK7A) plus or minus %15 (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 plus or minus 15%	X	X	X	X	2(m)	1(n)	Consider the pump inoperable and comply within 7 days (See note q).

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 Operable Instrument Channels Per Operable Trip Systems	Action Required*

* 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 600 psig 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.D 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.D 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 shutdown 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 8 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

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 Operable Instrument Channels Per Operable Trip Systems	Action Required*

of the active fuel.

l. Bypassed in IRM Ranges 8, 9, & 10.

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 operable 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 plus or minus 15% during a LOCA by relays SK7A and SK8A.

bb. Pump circuit breakers will trip instantaneously during a LOCA.

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 permisssible 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.

TABLE 3.5.1

SAFETY RELATED SNUBBERS

Snubber Number	Location	Elevation	Snubbers In High Radiation Area During Shut Down	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
N-1-1	North Main Steam	23'	X		X	
N-1-2	North Main Steam	23'	X		X	
N-1-3	North Main Steam	51'	X		X	
N-1-4	North Main Steam	51'	X		X	
N-1-5	North Main Steam	51'	X		X	
N-1-6	North Main Steam	51'	X		X	
N-1-7	North Main Steam	60'	X		X	
N-2-1	North Feedwater	23'	X		X	
N-2-2	North Feedwater	23'	X		X	
N-2-3	North Feedwater	51'	X		X	
N-2-4	North Feedwater	51'	X		X	
N-2-5	North Feedwater	51'	X		X	
N-2-6	North Feedwater	51'	X		X	
N-2-7	North Feedwater	51'	X		X	
N-2-8	North Feedwater	51'	X		X	
S-1-1	South Main Steam	23'	X		X	
S-1-2	South Main Steam	23'	X		X	
S-1-3	South Main Steam	51'	X		X	
S-1-4	South Main Steam	51'	X		X	
S-1-5	South Main Steam	51'	X		X	
S-1-6	South Main Steam	51'	X		X	
S-1-7	South Main Steam	60'	X		X	
S-2-1	South Feedwater	23'	X		X	
S-2-2	South Feedwater	23'	X		X	
S-2-3	South Feedwater	51'	X		X	
S-2-4	South Feedwater	51'	X		X	
S-2-5	South Feedwater	51'	X		X	
S-2-6	South Feedwater	51'	X		X	
S-2-7	South Feedwater	51'	X		X	
S-2-8	South Feedwater	51'	X		X	
N-14-1	Emergency Condenser Condensate Return	75'	X		X	
N-14-2	Emergency Condenser Condensate Return	75'	X		X	
N-14-3	Emergency Condenser Condensate Return	95'	X		X	
N-14-4	Emergency Condenser Condensate Return	95'	X		X	
N-14-5	Emergency Condenser Condensate Return	95'	X		X	

TABLE 3.5.1

SAFETY RELATED SNUBBERS

Snubber Number	Location	Elevation	Snubbers In High Radiation Area During Shut Down	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
N-14-6	Emergency Condenser Condensate Return	95'	x		X	
S-14-1	Emergency Condenser Condensate Return	60'	X		X	
S-14-2	Emergency Condenser Condensate Return	60'	X		X	
S-14-3	Emergency Condenser Condensate Return	95'	X		X	
S-14-4	Emergency Condenser Condenser Return	95'	X		X	
S-14-5	Emergency Condenser Condenser Return	95'	X		X	
S-14-6	Emergency Condenser Condensate Return	95'	X		X	
16-1	Cleanup	60'	X		X	
16-2	Cleanup	51'	X		X	
16-3	Cleanup	55'	X		X	
16-4	Cleanup	65'	X		X	
N-20-1	North Core Spray	51'	X		X	
N-20-2	North Core Spray	51'	X		X	
N-20-3	North Core Spray	75'	X		X	
N-20-4	North Core Spray	75'	X		X	
S-20-1	South Core Spray	90'		X	X	
S-20-2	South Core Spray	95'	X		X	
S-20-3	South Core Spray	95'		X	X	
N-E-1	North Electromatic Relief	51'	X		X	
N-E-2	North Electromatic Relief	51'	X		X	
S-E-1	South Electromatic Relief	51'	X		X	
S-E-2	South Electromatic Relief	51'	X		X	
S-E-3	South Electromatic Relief	51'	X		X	
21-1	Containment Spray	60'		X	X	
1	Containment Spray	-19'				X
2	Containment Spray	-19'				X
3	Containment Spray	-19'				X
4	Containment Spray	-19'				X
5	Containment Spray	-19'				X

TABLE 3.5.1

SAFETY RELATED SNUBBERS

Snubber Number	Location	Elevation	Snubbers In High Radiation Area During Shut Down	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
6	Outside Torus Cont. Spray	-19'				X
7	Outside Torus Cont. Spray	-19'				X
8	Outside Torus Cont. spray	-19'				X
9	Outside Torus Cont. Spray	-19'				X
10	Outside Torus Cont. Spray	-19'				X
12	Outside Torus Cont. Spray	-19'				X
13	Outside Torus Cont. Spray	-19'				X
14	Outside Torus Cont. Spray	-19'				X
15	Outside Torus Cont. Spray	-19'				X
16	Outside Torus Cont. Spray	-19'				X
17	Outside Torus Cont. Spray	-19'				X
18	Core Spray	-19'		X		X
19	Core Spray	-19'				X
1	Core Spray	20'				X
2	Core Spray	20'				X
3	Cont. Spray	20'		X		X
4	Cont. Spray	20'		X		X
5	Core Spray	20'		X		X
6	Core Spray	20'		X		X
1	Core Spray	23'				X
2	Core Spray Pump	23'				X
3	Cont. Spray	23'				X
4	Cont. Spray	23'				X
5	Cont. Spray	23'				X
6	Cont. Spray	23'				X
7	Cont. Spray	23'		X		X
1	Cont. Spray	51'				X
2	Cont. Spray	51'				X
3	Cont. Spray	51'				X
4	Cont. Spray	51'				X
5	Core Spray	51'				X
6	Core Spray	51'				X
7	Core Spray	51'				X
8	Core Spray	51'				X
9	Core Spray	51'				X
10	Core Spray	51'				X
21	Core Spray	51'				X
22	Core Spray	51'				X
23	Core Spray	51'				X
24	Core Spray	51'				X

TABLE 3.5.1

SAFETY RELATED SNUBBERS

Snubber Number	Location	Elevation	Snubbers In High Radiation Area During Shut Down	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
1	Core Spray	75'				X
2	Core Spray	75'				X
3	Core Spray	75'				X
4	Core Spray	75'				X
5	Core Spray	75'				X
6	B. Emer. Cond.	75'				X
7	A. Emer. Cond.	75'				X
8	A. Emer. Cond.	75'				X
9	B. Emer. Cond.	75'				X
10	A. Emer. Cond.	75'				X
11	A. Emer. Cond.	75'				X
12	A. Emer. Cond.	75'				X
13	B. Emer. Cond.	75'				X
14	A. Emer. Cond.	75'				X
15	B. Emer. Cond.	75'				X
16	A. Emer. Cond.	75'				X
17	A. Emer. Cond.	75'				X
18	A. Emer. Cond.	75'				X
19	A. Emer. Cond.	75'				X
20	A. Emer. Cond.	75'				X
21	B. Emer. Cond.	75'				X
22	A. Emer. Cond.	75'				X
23	A. Emer. Cond.	75'				X
24	A. Emer. Cond.	75'				X
25	B. Emer. Cond.	75'				X
1	A. Emer. Cond.	95'				X
2	A. Emer. Cond.	95'		X		X
3	A. Emer. Cond.	95'		X		X
4	A. Emer. Cond.	95'				X
5	B. Emer. Cond.	95'				X
6	B. Emer. Cond.	95'				X
7	B. Emer. Cond.	95'				X
8	B. Emer. Cond.	95'				X
9	B. Emer. Cond.	95'				X
17-1	Shutdown Cooling	48'	X		X	
17-2	Shutdown Cooling	51'	X		X	
17-3	Shutdown Cooling	51'	X		X	
17-4	Shutdown Cooling	51'	X		X	
17-5	Shutdown Cooling	51'	X		X	
17-6	Shutdown Cooling	51'	X		X	

TABLE 3.5.1

SAFETY RELATED SNUBBERS

Snubber Number	Location	Elevation	Snubbers In High Radiation Area During Shut Down	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
51-7	Shutdown Cooling	51'				X
51-8	Shutdown Cooling	51'				X
51-9	Shutdown Cooling	51'				X
51-10	Shutdown Cooling	51'				X
51-11	Shutdown Cooling	51'				X
51-12	Shutdown Cooling	51'				X
51-13	Shutdown Cooling	51'				X
51-14	Shutdown Cooling	51'				X
51-15	Shutdown Cooling	51'				X
51-16	Shutdown Cooling	51'				X
51-17	Shutdown cooling	51'				X
51-18	Shutdown Cooling	51'				X
51-19	Shutdown Cooling	51'				X
51-20	Shutdown Cooling	51'				X

If radiation levels in the vicinity of snubbers change, appropriate modifications to this Table should be submitted to NRC as an attachment to any subsequent license amendment.

TABLE 3.5.2

CONTAINMENT ISOLATION VALVES

VALVE FUNCTION/VALVE DESIGNATION	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 & 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

TABLE 3.6.1

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

Nuclide	Ni*	Mi+
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

*mrad-m(3)/pci-yr
Source: Regulatory Guide 1.109, Revision 1, October 1977, Table B-1.
+mrad/ci
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
Mm-54	9.5E03	1.3E09	1.8 E08
Mm-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
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

TABLE 3.6.2

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

NUCLIDE	Rii*	Rgi**	Rvi**
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
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	1.7 E07	2.4 E10

TABLE 3.6.2

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

NUCLIDE	Rii*	Rgi**	Rvi**
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
W-187	4.3	2.4 E06	1.7 E04
Np-239	2.3 E01	1.7 E06	1.3 E02

TABLE 3.6.2

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

NUCLIDE	Rii*	Rgi**	Rvi**

* 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)

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 +
	" 38'/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 rm.)
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*+

TABLE 3.12.1 FIRE DETECTION INSTRUMENTATION

Fire Area/Zone	Location	Detector Zone	Required # of Detectors
	"	B-Zone 2	7*+
	"	C-Zone 1	1 +
	"	C-Zone 2	1 +
	"	Duct	1
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)
10/1	Laundry Room	Sprinkler Sys. #13	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 +

TABLE 3.12.1 FIRE DETECTION INSTRUMENTATION

Fire Area/Zone	Location	Detector Zone	Required # of Detectors

*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
10	Laundry Room	Sprinkler Sys. #13
11	Condenser Bay	Sprinkler Sys. #2
11	Turbine Lube Oil Bay	Deluge Sys. #3
11	Turbine Basement South	Sprinkler Sys. #9
12	Transformers	Deluge Sys. #1
	"	Deluge Sys. #2
18	Fire Water Pump House	Deluge Sys. #9

<u>TABLE 3.12.3 HOSE STATIONS</u>

Fire Area	Zone	Hose Station No.	Locations
11	2	3	Turbine Basement - S
11	2	4	Turbine Basement - S
11	1	8	Turbine 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'

TABLE 3.12.3 HOSE STATIONS

Fire Area	Zone	Hose Station No.	Locations
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	Control Room
10	1	54	Chem. Lab.
11	2	55	Turbine 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 (Office Bldg.)	1
Cable Tray Room		Instrument Shop (Office Bldg.)	
2. 480 Volt Switchgear	6	23' Elev. Between Rx. Bldg. & Turbine 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

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
or		
Relief Valve Position Indicator (Backup Indications**)	1/valve	

* Accoustic Monitor
** Thermocouple

TABLE 4.1.1
MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY 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	1/d	1/3 mo.	Note 1	By application of test pressure
4.	Low-Low Water Level	1/d	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	1/3 mo.	Note 1	By application of test pressure
10.	Main Steam Isolation Valve (Scram)	N A	N A	1/3 mo.	By exercising valve
11.	APRM Level	N A	1/3d	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/wk	Using built-in calibration equipment during power operation
	b. Sensors for 13(a)	N A	Each refuel ing outage	NA	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	N A	During approach to shutdown only

TABLE 4.1.1

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
		shutdown		
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 refuel ing outage	Each refuel ing outage	
19. Manual Scram Buttons	N A	N A	1/3 mo	
20. High Temperature Main Steamline Tunnel	N A	Each refuel ing outage	Each refuel ing outage	Using heat source box
21. SRM	*	*	*	Using built-in calibration equipment
22. Isolation Condenser High Flow Delta P (Steam and Water)	N A	1/3 mo	1/3 mo	By application of test pressure
23. Turbine Trip Scram	N A	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 refuel ing 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 refuel ing Outage	Every 3 months	By varying level in switch column
b) Scram trip bypass	N A	N A	Each refuel ing outage	

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)

TABLE 4.1.1

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
(a) and (2) (a).				

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

Legend: N A = Not applicable; 1/s = Once per shift; 1/d = Once per day; 1/3d = Once per 3 days; 1/wk = Once per week; 1/3 mo = Once every 3 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	"
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 Buildings Isolation and SGTS Initiation	Same as for respective instrumentation in Table 4.1.1
11) Condenser Vacuum Pump Isolation	Prior to each startup

TABLE 4.3.1

EXAMINATION SCHEDULE OF REACTOR COOLANT SYSTEM (See Note 3)

Component	Sample	Extent	Inspection Process (See Note 1)	Inspection Frequency (See Note 2)
A. REACTOR VESSEL				
1. Flange studs	100%	Entire volume from end	UT	b
		Exposed surfaces	VT	b
2. Flange stud washers and nuts	100%		VT	b
3. Steam nozzle	One	100% nozzle to shell weld	RT & VT	a
		100% exterior nozzle surface	VT	a
		100% nozzle to pipe weld	RT & VT	a
4. Core spray nozzle (exterior surface)	One	100% nozzle to shell weld	VT	a
		Safe end to nozzle weld	VT	a
		Safe end to pipe weld	VT	a
5. Control rod drive penetrations	10% selected of total	Interior circumference opposite housing to stub tube weld	UT	c
6. Recirculation inlet nozzle safe end welds	One	100% safe end to nozzle dissimilar metal weld	RT & VT	a
		100% safe end to pipe weld	RT & VT	a
7. Circumferential weld head to head flange	One	10% of weld length including 2 intersects with longitudinal welds	RT & VT	a
8. Longitudinal	One	Entire length	RT &	a

TABLE 4.3.1

EXAMINATION SCHEDULE OF REACTOR COOLANT SYSTEM (See Note 3)

Component	Sample	Extent	Inspection Process (See Note 1)	Inspection Frequency (See Note 2)
weld on head from flange weld to cap			VT	
9. Integrally welded internal vessel components:				
Core spray piping	One	Entire accessible surfaces and welds	VT	a
Core spray sparger	One	Entire accessible surfaces and welds	VT	e
Shroud support ring	Partial	Any accessible surface	VT	a
Liquid poison sparger	Partial	Any accessible surface and/or welds	VT	a
10. Cladding on head	2 patches	Surface	VT	a
11. Cladding on shell	2 patches	Surface	VT	a
B. PRIMARY SYSTEM PIPING IN DRYWELL				
1. Recirculation, main steam and core spray	10% of circumferential welds greater than 4" in diameter in one loop of each of the 3 systems	Entire circumferemce and 2" of the longitudinal welds each side	RT & VT	a
2. Pressure-retaining bolting in piping		As removed for maintenance	VT	d

TABLE 4.3.1

EXAMINATION SCHEDULE OF REACTOR COOLANT SYSTEM (See Note 3)

Component	Sample	Extent	Inspection Process (See Note 1)	Inspection Frequency (See Note 2)
3. Piping supports and hangers	1 set in 1 loop of each of 3 systems	Load-bearing welds	VT	d
C. RECIRCULATION PUMPS				
1. Pump casing seam welds	One each	Interior surface when disassembled	VT	d
2. Pressure-retaining bolting 2" and larger	100%	As removed for maintenance	VT & UT	d
3. Integrally welded supports	One	Load-bearing welds	VT & UT	d
D. PRIMARY VALVES				
1. Valves 3" and over	One each type on recirc., main steam, & core spray systems	Inside surface and body seam welds when disassembled	VT	d
2. Pressure-retaining bolting 2" and larger	100%	As removed for maintenance	VT & UT	d
3. Supports and hangers	1 set in one loop of the recirc., main steam & core spray systems	Load-bearing welds	VT	d

NOTES:

1. UT Ultrasonic examination

RT Radiographic examination (UT acceptable alternate for RT)

TABLE 4.3.1

EXAMINATION SCHEDULE OF REACTOR COOLANT SYSTEM (See Note 3)

Component	Sample	Extent	Inspection Process (See Note 1)	Inspection Frequency (See Note 2)

VT Examination by viewing

2\. a. Inspect same sample twice during first 5 years of operation

b. 100% inspect partial sample during at least two inspections such that 100% of the studs are inspected during the first 5 years of operation

c. Inspect partial sample during at least two inspections such that 10% of the penetrations are inspected during the first 5 years of operation

d. Normal maintenance observations - Examination by viewing, where accessible, during maintenance.

e. Full inspections of the accessible surfaces and welds of both spargers and the repair assembly on core spray sparger no. 2 shall be carried out during each of the next five refueling outages beginning in 1979, subsequent inspections will be conducted at 5 year intervals.

3\. The examination schedule of Table 4.3.1, extent of examination, inspection process, and inspection frequency shall be reviewed after the fourth year of operation and a revised specification for subsequent inservice inspection developed.

TABLE 4.3.2
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.

TABLE 4.13.1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Relief and Safety Valve Position Indicator (Primary Detector*)	A	B
Relief and Safety Valve Position Indicator (Backup Indications**)	A	B

Legend:

A = at least once per 31 days; B = at least once per 18 months (550 days).

*Acoustic Monitor
**Thermocouple

TABLE 6.5.1 SAFETY REVIEW RESPONSIBILITIES

ITEM	INITIAL ACTION	PORC	INDEPENDENT REVIEW ISRG	GORB
a) Proposed change to equipment, or systems subject to the Provisions of Section 50.59, Part 50, Title 10 Code of Federal Regulations.	Initiator: Must prepare a complete description of the proposed changes and ensure a safety evaluation of the change is included. Vice President & & Director (1) must determine if the item is an actual change to equipment or systems as described in the FSAR. (2) Must determine if the item involves an unreviewed safety question. (3) May request the PORC to assist in the above determinations.	Must review items to determine whether or not an unreviewed safety question is involved, if requested by the Vice President & Director	Must review all determinations by the Vice president & Director	May review any determination, but must review those for which the Vice President & Director has requested GORB review.
b) Proposed tests and experiments, (Subject to Provisions of) 50.59, Part 50, Title 10, Code of Federal Regulations.	Initiator: Must prepare a complete description of the proposed test or experiment and ensure a safety evaluation of the test or experiment is included. Vice President & Director (1) Must determine if the item involves an unreviewed safety question. (2) May request the PORC to assist in the above determinations.	Must review item to determine whether or not an unreviewed safety question is involved, if requested by the Vice President & Director.	As above.	As above.
c) Proposed changes in Technical Specifications or in the NRC Operating License.	Initiator: Must prepare a complete description of the proposed change and ensure a safety evaluation of the change is included.	(1) Must review the item for nuclear and radiological safety. (2) Must make recommendations to the Vice President & Director as to whether or not the change is safe.	Must review change and PORC recommendation prior to submittal to the NRC.	May review any item but must review those for which the Vice President & Director or his supervisor have requested GORB review.
d) Reportable Occurrences	Vice President & Director: Must have investigations performed for all Reportable	Must review Reportable Occurrences Report for safety significance and make recommendations to	Must review Reportable Occurrence Reports for safety significance and review PORC recommenda-	As above.

TABLE 6.5.1 SAFETY REVIEW RESPONSIBILITIES

ITEM	INITIAL ACTION	PORC	INDEPENDENT REVIEW ISRG	GORB
	Occurrences and a report prepared including the safety significance of the incident.	the Vice President & Director on how to avoid reccurrence.	tions.	
e) Facility operations including Security Plan, Emergency Plan and implementing procedures; review is to detect potential safety hazards.		Continuing responsibility	See Item i below	As above
f) Significance operation abnormalities or deviations from normal and expected performance.	Vice President & Director Report such matters to the PORC ,ISRG Coordinator and the Chairman GORB.	Review matter and report evaluation of safety significance to the ISRG and GORB.	Perform independent review of PORC evaluation.	As above
g) Any indication of an unanticipated deficiency in some aspect of design or operation of safety related structures, systems, or components.	As above	As above	As above	As above
h) PORC minutes and reports			Review to determine if any matters discussed involve unrelated safety questions.	As above
i) Audit Reports and NRC Inspection Reports.			Review to determine if any matters reported involved Violations of Technical Specifications license requirements or regulations or have any nuclear or radiation safety implications.	The report of the management review of the QA Plan, initiated by the Vice President, and Director Oyster Creek in accordance with the Operational Quality Assurance Plan, shall be reviewed by the GORB with respect to technical and administrative safety issues.

FIGURE 2.1.1

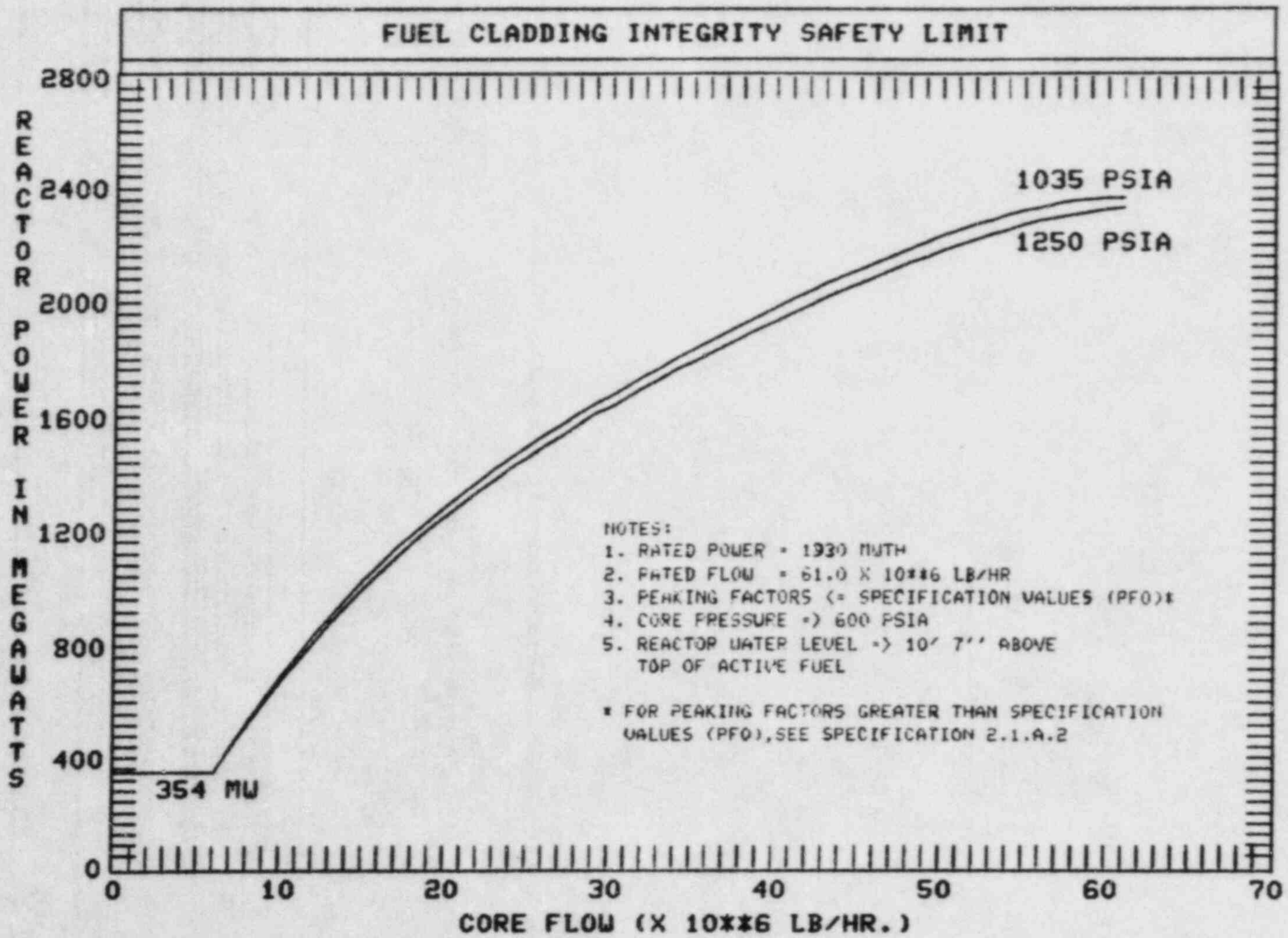

FUEL CLADDING INTEGRITY SAFETY LIMIT
REACTOR POWER IN MEGAWATTS
0
400
800
1200
1600
2000
2400
2800
CORE FLOW (X 10**6 LB/HR.)
0
10
20
30
40
50
60
70
1035 PSIA
1250 PSIA
354 MW
NOTES:
1. RATED POWER = 1930 MWTH
2. RATED FLOW = 61.0 X 10**6 LB/HR
3. PEAKING FACTORS <= SPECIFICATION VALUES (PFO)*
4. CORE PRESSURE => 600 PSIA
5. REACTOR WATER LEVEL => 10' 7'' ABOVE
TOP OF ACTIVE FUEL
* FOR PEAKING FACTORS GREATER THAN SPECIFICATION
VALUES (PFO), SEE SPECIFICATION 2.1.A.2

Figure 3.2.1

Sodium Pentaborate Solution
Volume - Concentration Requirements

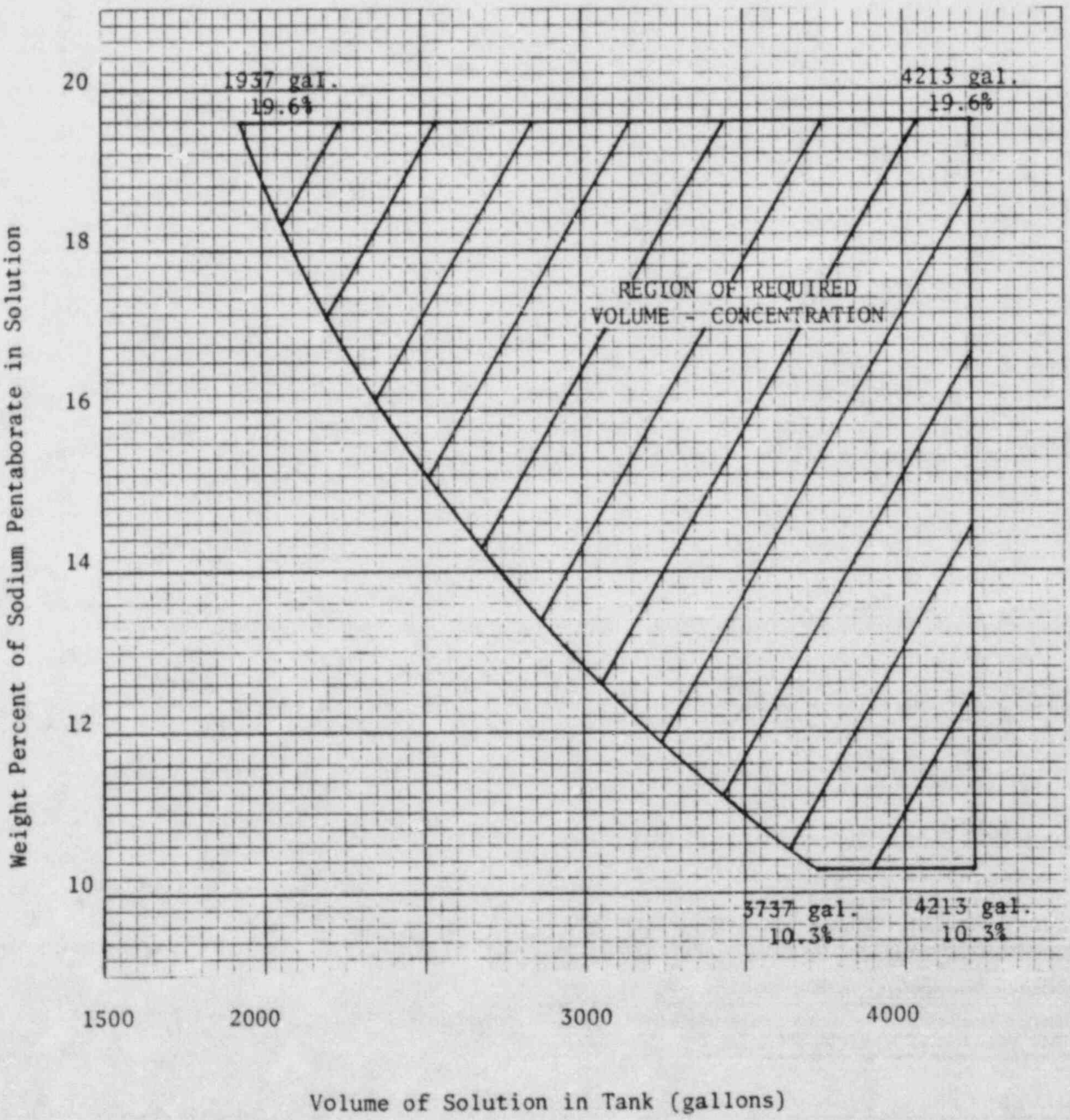


FIGURE 3.2.2

Sodium Pentaborate Solution

Temperature Requirements

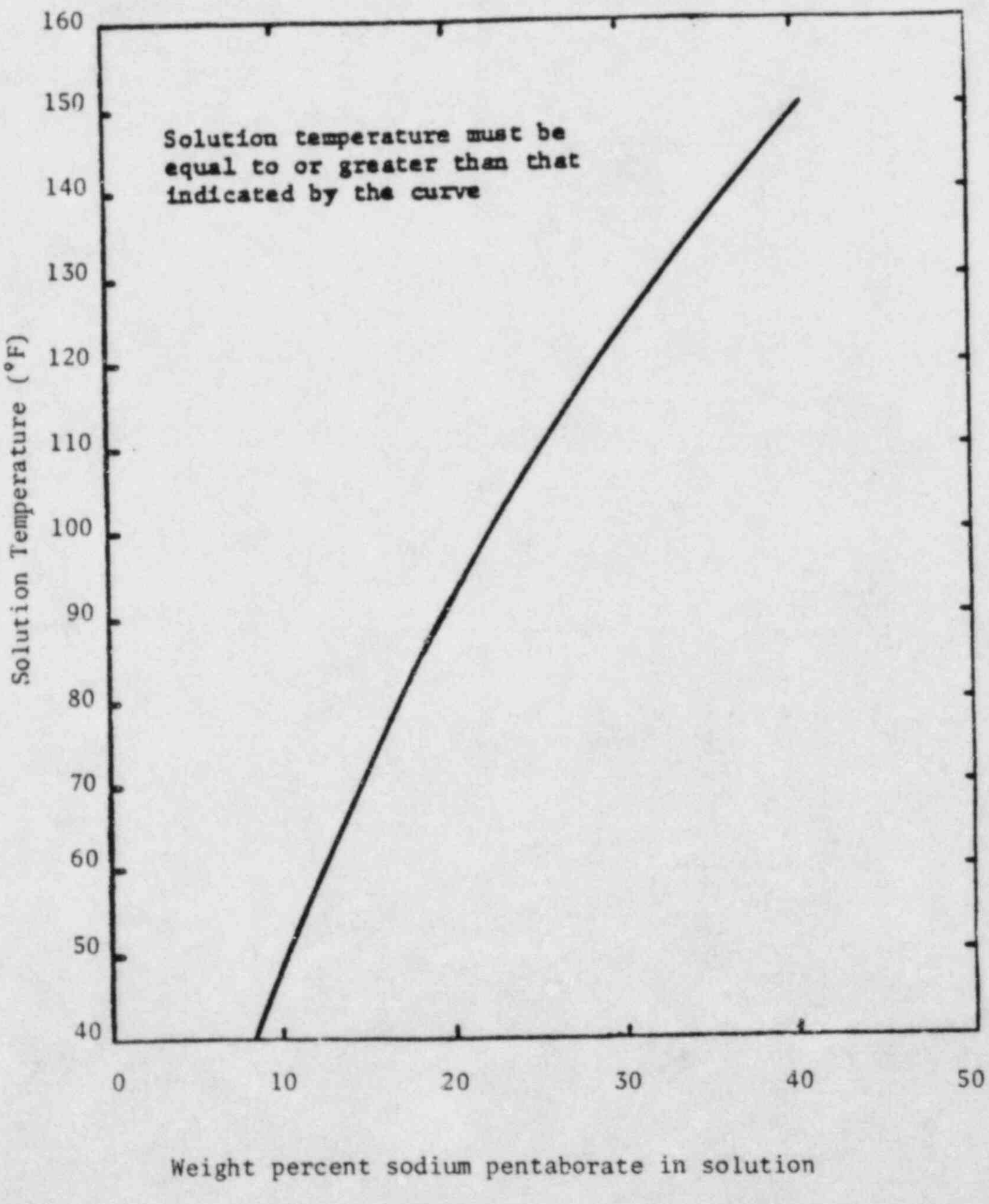


Figure 3.3.1

Oyster Creek Nuclear Generating Station Reactor Vessel
Pressure/Temperature Limits
For Up To Ten Effective Full Power Years of Core Operation

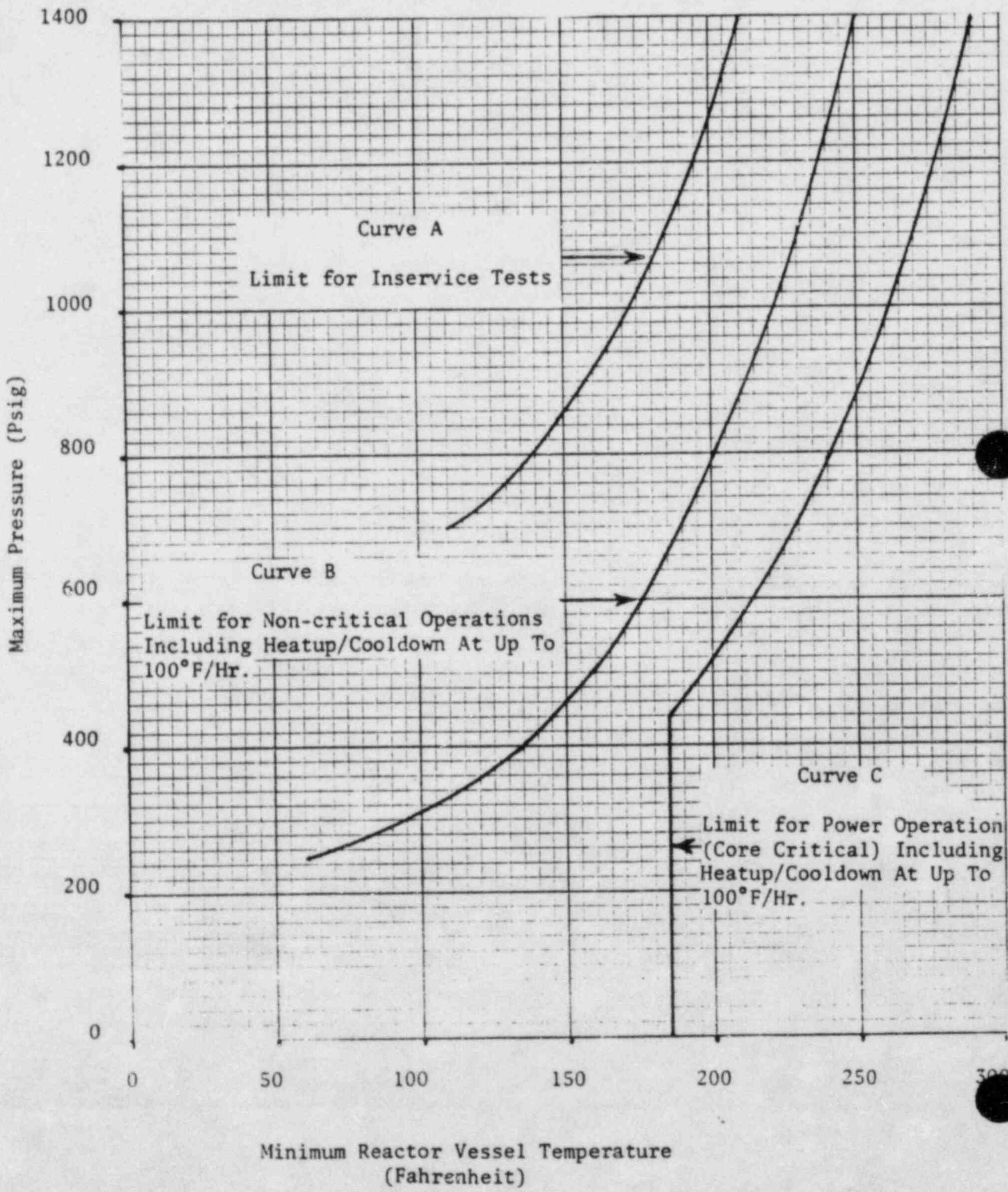
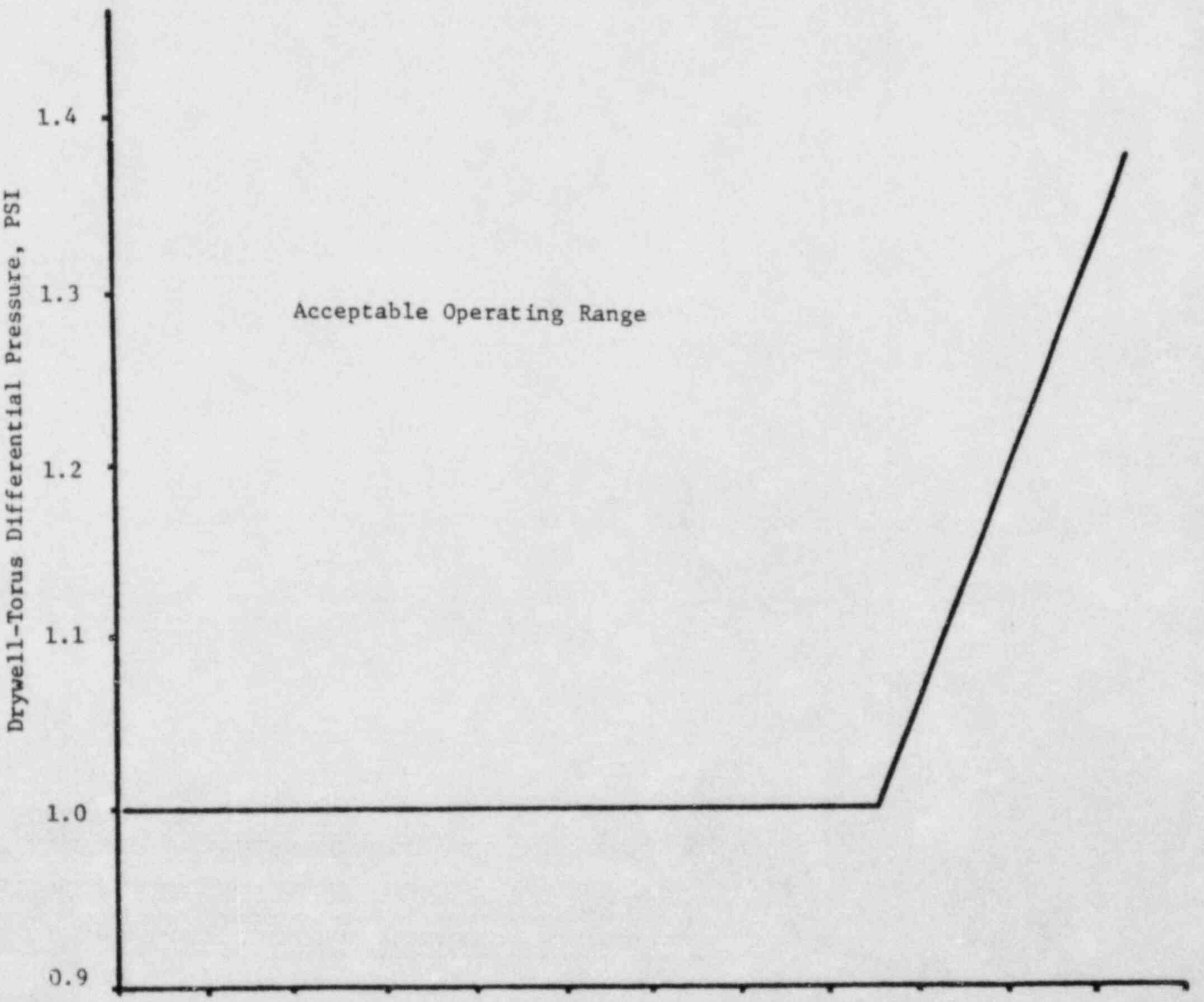


Figure 3.5.1

Required Drywell to Torus
Differential Pressure



*The actual acceptable range of downcomer submergence is governed by the Technical Specifications limit on maximum and minimum water volume in the torus(see section 3.5.A.1). This actual acceptable range of downcomer submergence will not encompass the full range of downcomer submergence indicated in the figure above.

FIGURE 3.10.1

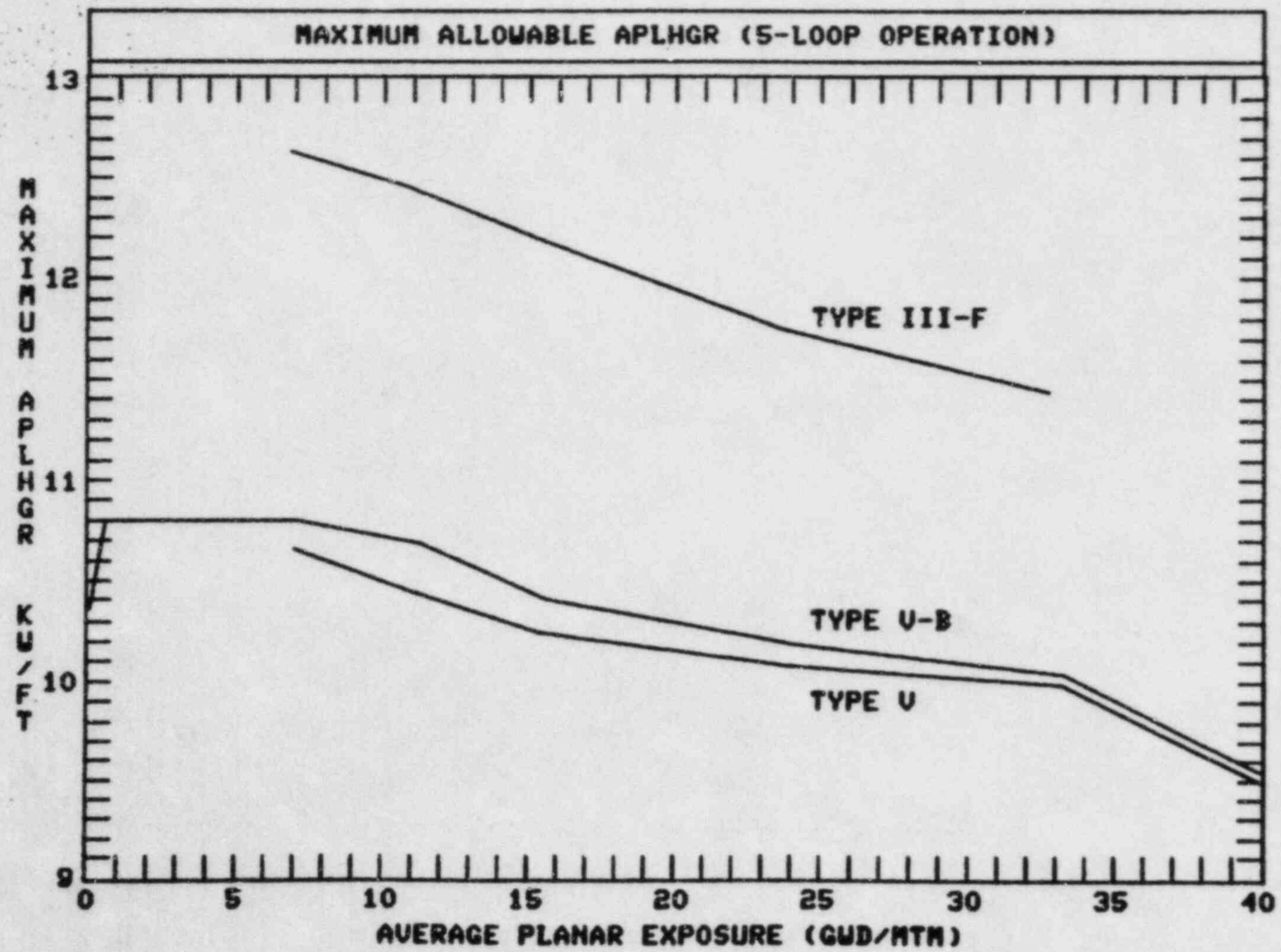
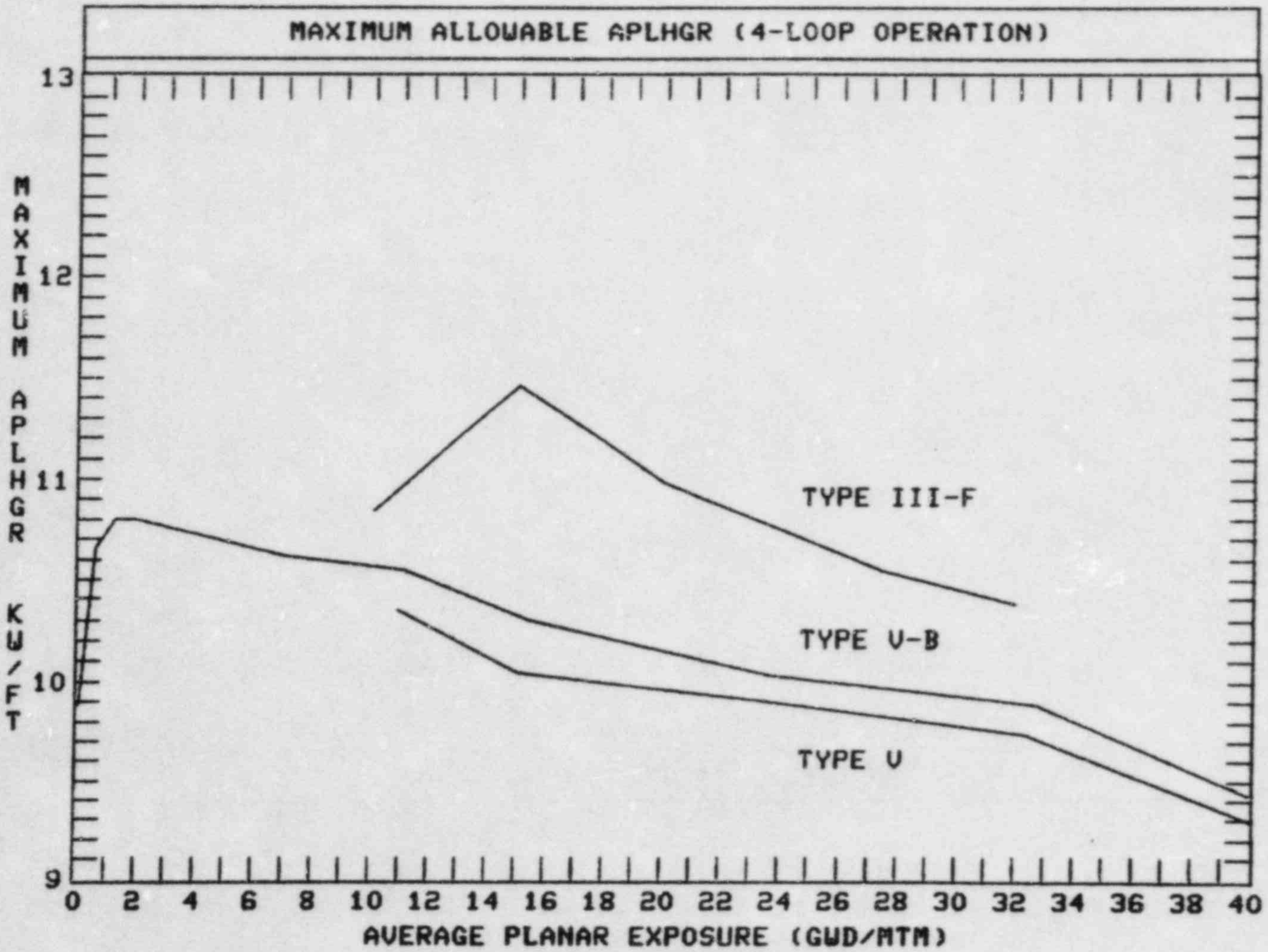

MAXIMUM ALLOWABLE APLHGR (5-LOOP OPERATION)
MAXIMUM APLHGR KW/FT
13
12
11
10
9
0
5
10
15
20
25
30
35
40
AVERAGE PLANAR EXPOSURE (GWD/MTM)
TYPE III-F
TYPE V-B
TYPE V

FIGURE 3.10.2



MAXIMUM ALLOWABLE APLHGR (4-LOOP OPERATION)
MAXIMUM APLHGR KW/FT
13
12
11
10
9
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40
AVERAGE PLANAR EXPOSURE (GWD/MTM)
TYPE III-F
TYPE V-B
TYPE V

FIGURE 3.10.3

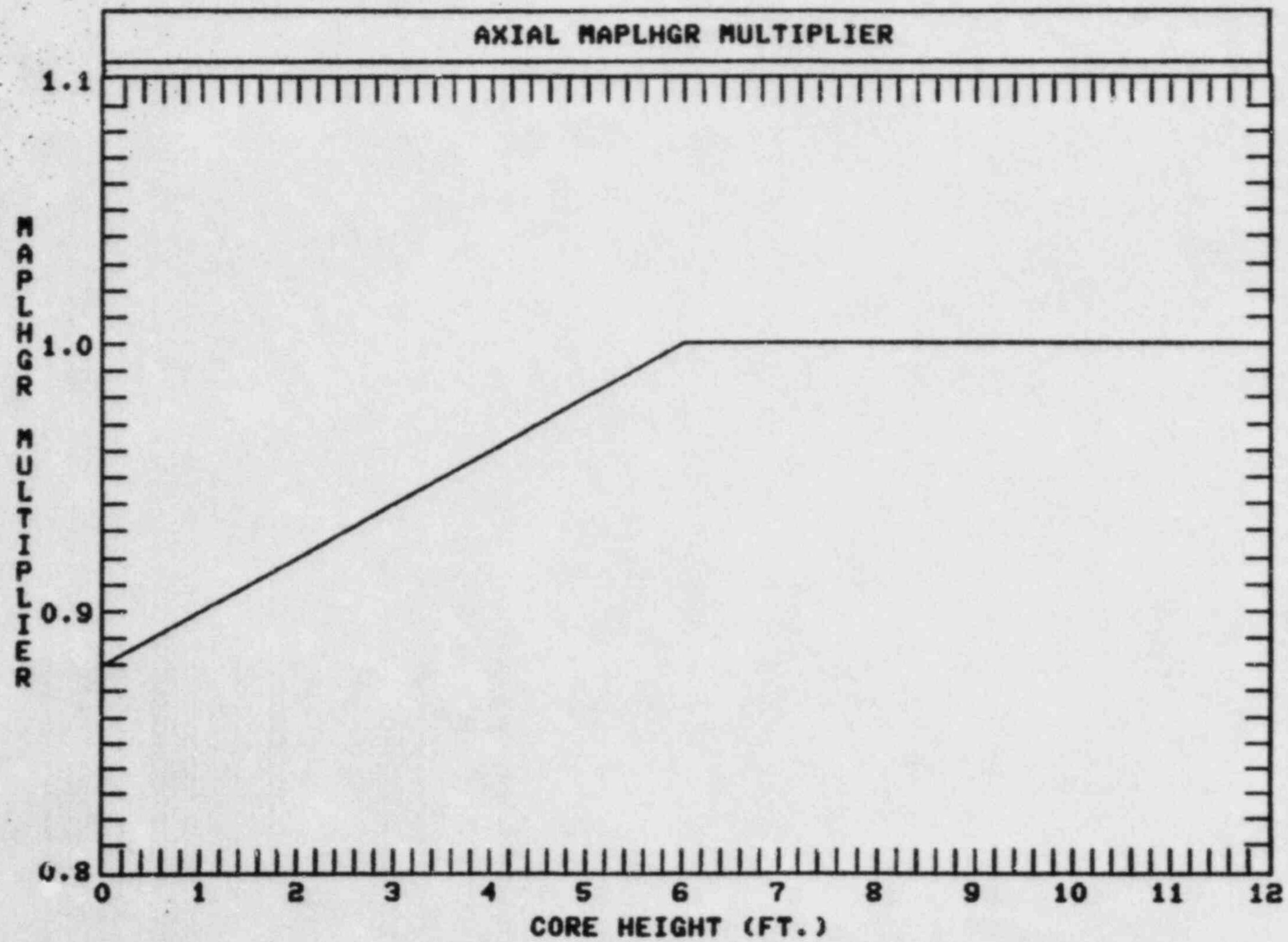

AXIAL MAPLHGR MULTIPLIER
MAPLHGR MULTIPLIER
1.1
1.0
0.9
0.8
0
1
2
3
4
5
6
7
8
9
10
11
12
CORE HEIGHT (FT.)

Figure 4.1.1

Failures Versus Time in Service

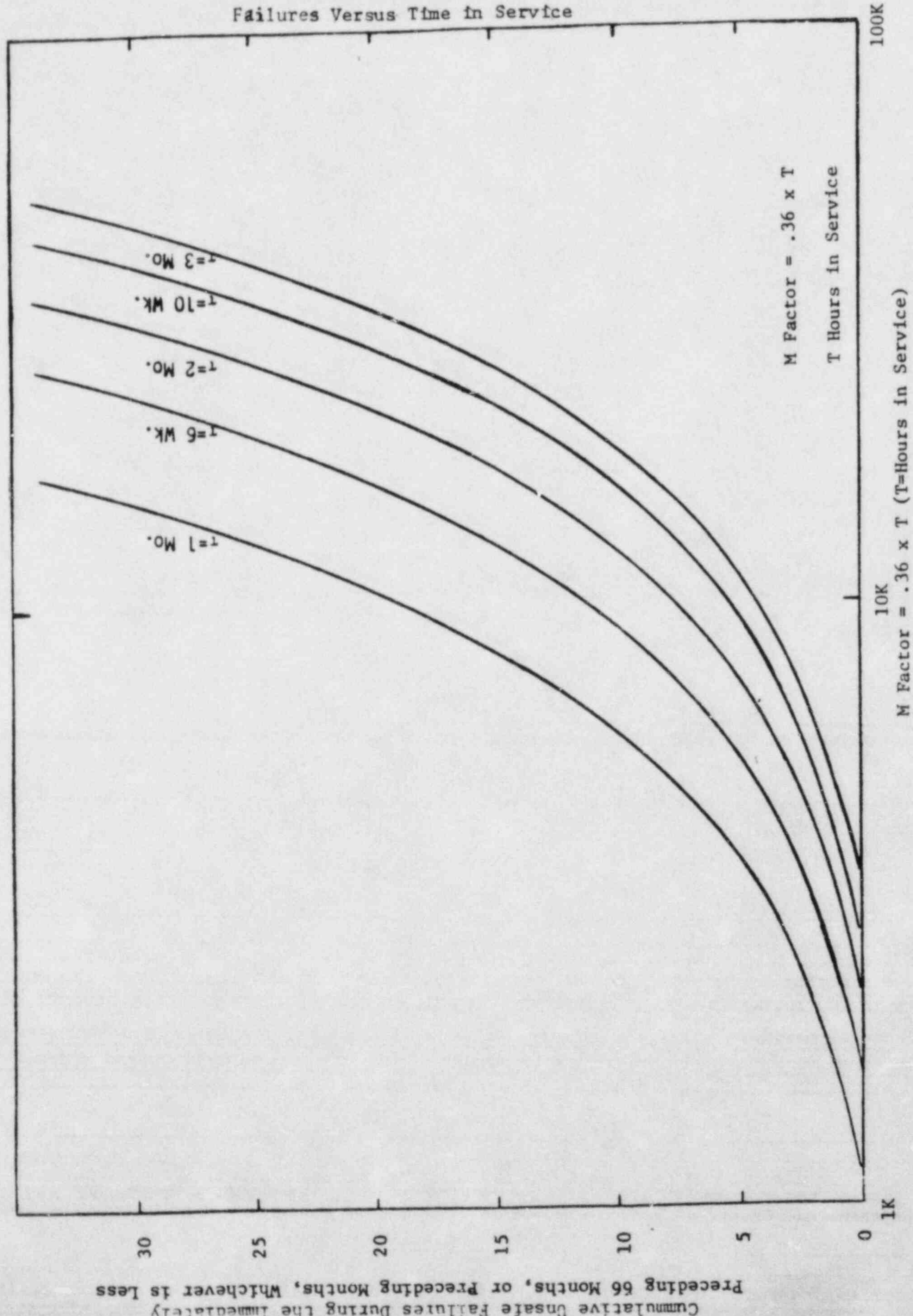


Figure 4.5.1

HEPA Filter Maximum Allowable
Pressure Drop

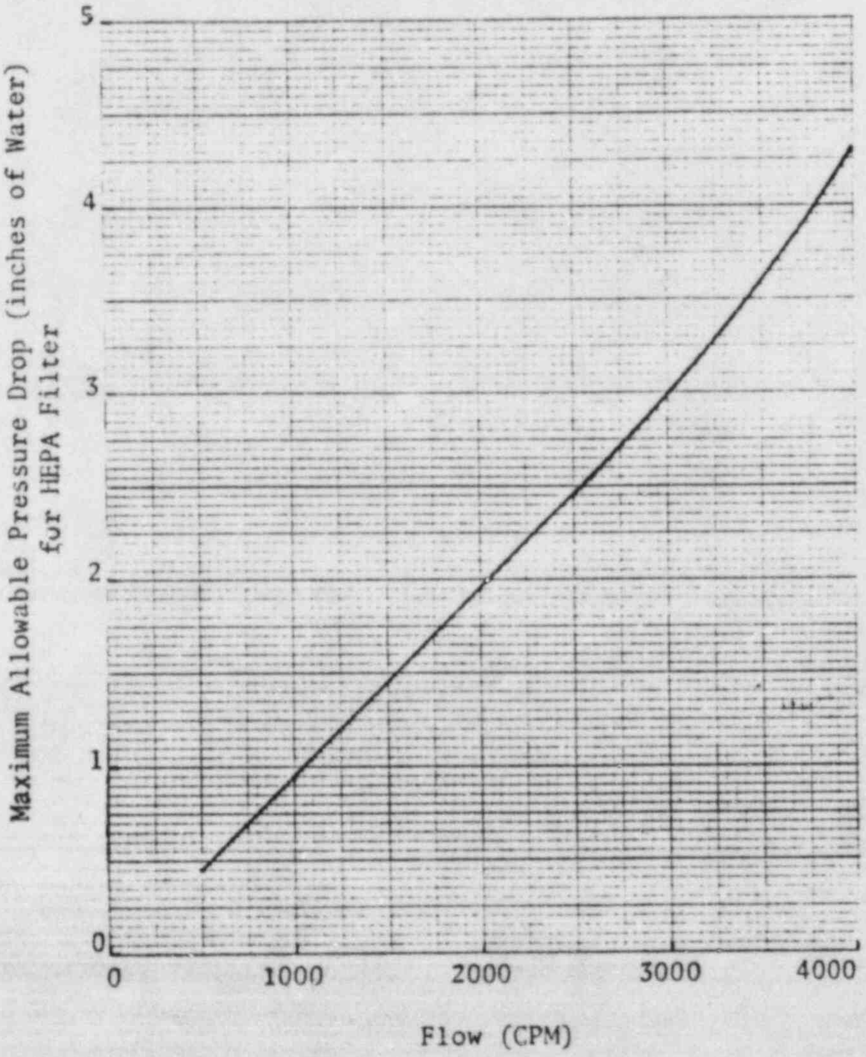
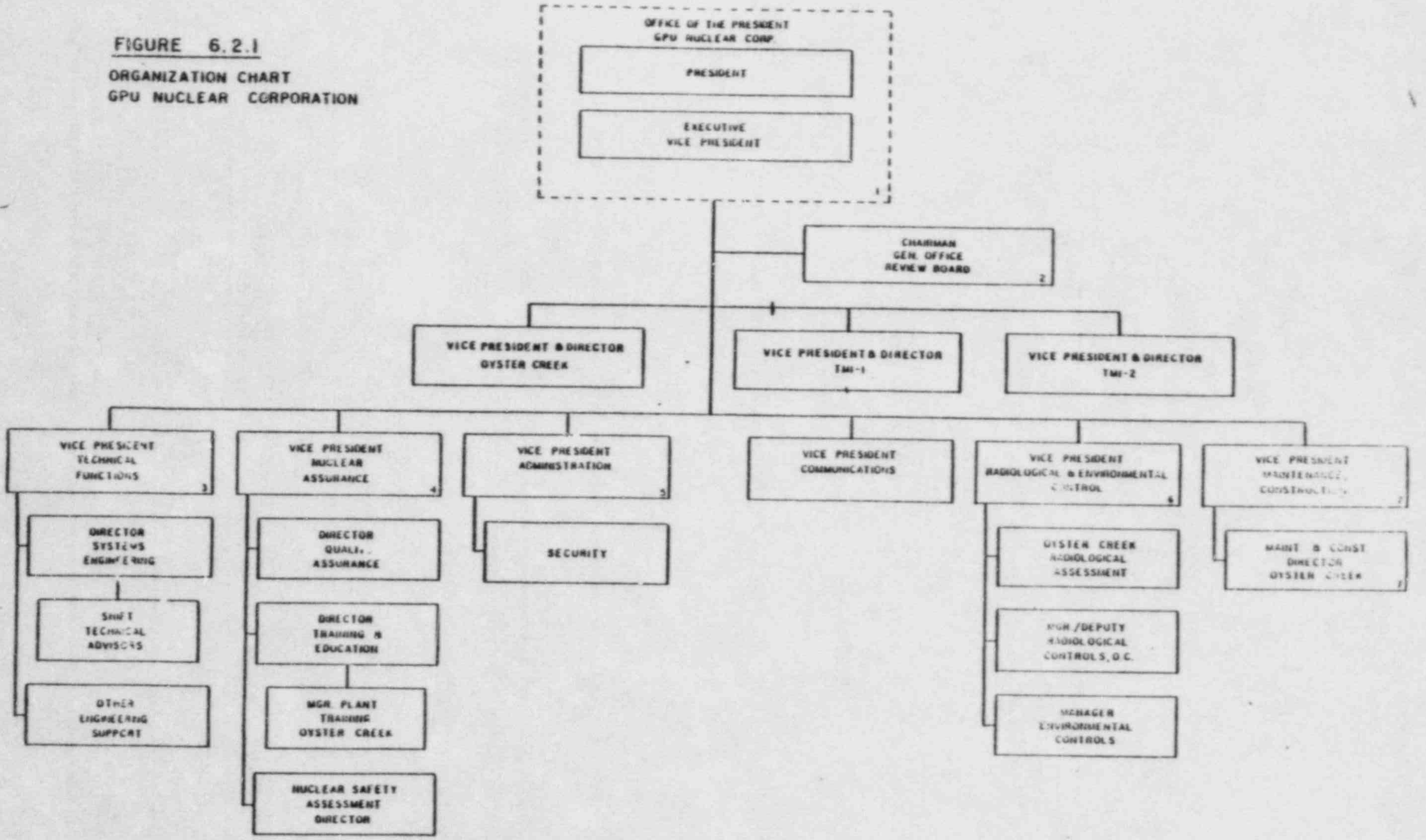


FIGURE 6.2.1

ORGANIZATION CHART
GPU NUCLEAR CORPORATION



Amendment No. ~~50~~, ~~59~~, 68

NOTES TO FIGURE 6.2.1

1. The President of the GPU Nuclear Corporation is a Senior Vice President of Met-Ed and is a Vice President of JCP&L. The Executive Vice President is a Vice President of both JCP&L and Med-Ed.

2. The General Office Review Board reports to and gets general direction from the Office of the President - GPU Nuclear Corporation. However, the CORB has direct access to the Presidents, Chief Executive Officers and Boards of Directors of the Companies involved.

3. The project engineering, the shift technical advisors, and licensing functions assigned to each nuclear plant site will report to the Vice President Technical Functions.

4. The quality assurance, emergency planning and training functions assigned to each nuclear plant site will report to the Vice President Nuclear Assurance.

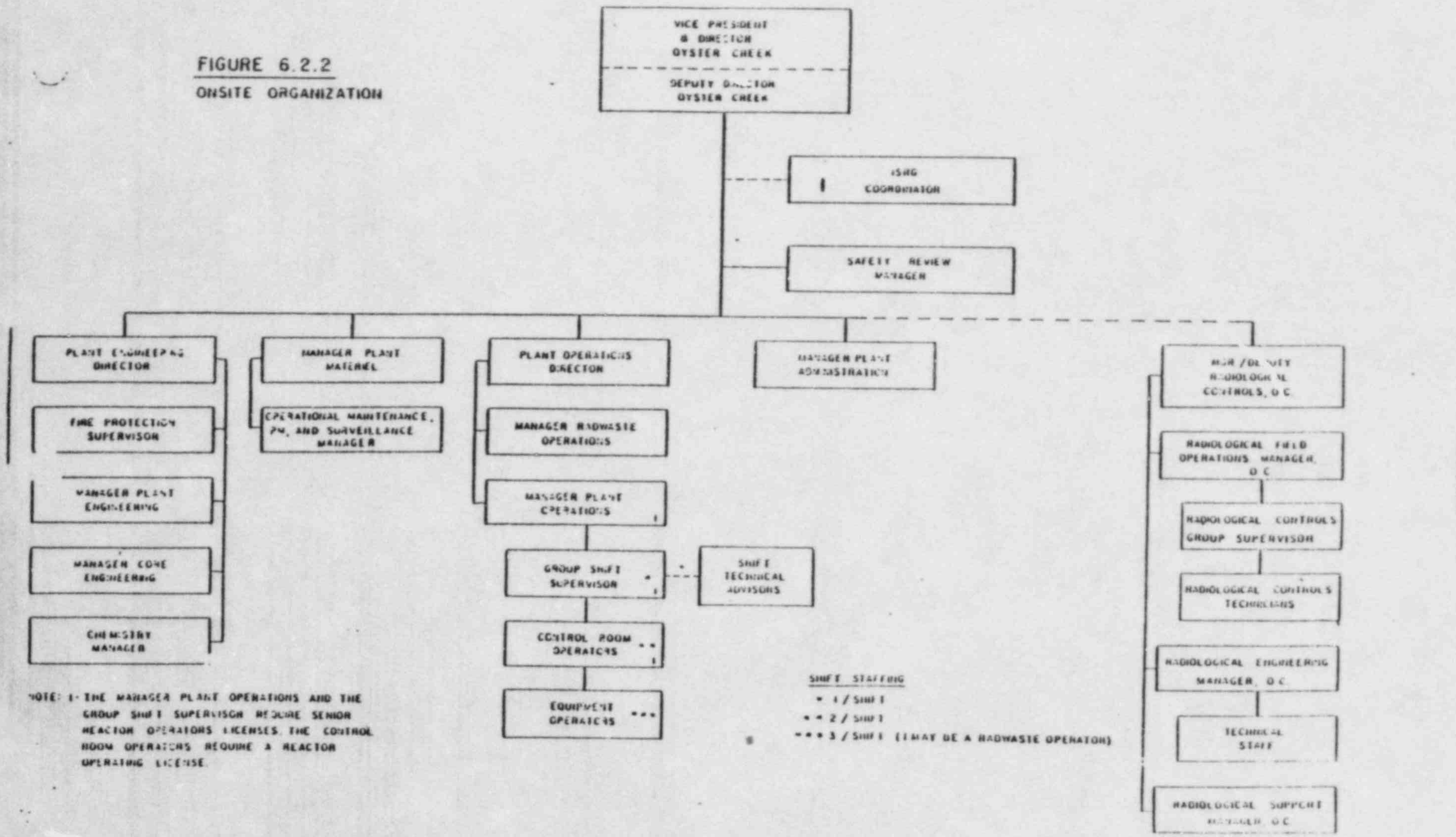
5. The security, materials management, personnel and general administrative functions asaigned to each nuclear plant site will report to the Vice President Administration.

6. The radiological and offsite environmental control functions assigned to each nuclear plant site will report to the Vice President Radiological and Environmental Controls.

7. 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 OPERATING LICENSE.

SHIFT STAFFING

* 1 / SHIFT

** 2 / SHIFT

*** 3 / SHIFT (1 MAY BE A RADWASTE OPERATOR)