ATTACHMENT 1

PROPOSED CHANGES TO APPENDIX A

TECHNICAL SPECIFICATIONS FOR

QUAD CITIES STATION UNIT 1

FACILITY OPERATING LICENSES DPR-29

Revised Pages: 1 thru 3-1, inclusive
(All pages of Appendix A to DPR-29 have been retyped for improved clarity)

4607K

QUAD CITIES
DPR-29

TECHNICAL SPECIFICATIONS

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1.0 DEFINITIONS

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

A. (Deleted)

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

C. Hot Standby - Hot standby means operation with the reactor critical, system pressure less than 1060 psig, the main steam isolation valves closed, and thermal power not exceeding 15%.

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

E. Instrument Calibration - An instrument calibration means the adjustment of an instrument signal output so that it corresponds, within acceptable range and accuracy, to a known value (values) of the parameter which the instrument monitors. Calibration shall encompass the entire instrument, including actuation, alarm, or trip. Response time is not part of the routine instrument calibration but will be checked once per operating cycle.

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

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

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

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

K. Logic System Functional Test - A logic system functional test means a test of all relays and contacts of a logic circuit from sensor to activated device to ensure all components are operable per design intent. Where possible, action will go to completion, i.e., pumps will be started and valves opened.

L. Modes of Operation - A reactor mode switch selects the proper interlocking for the operating or shutdown condition of the plant. Following are the modes and interlocks provided:

1. Shutdown - In this position, a reactor scram is initiated, power to the control rod drives is removed, and the reactor protection trip systems have been deenergized for 10 seconds prior to permissive for manual reset.

2. Refuel - In this position, interlocks are established so that one control rod only may be withdrawn when flux amplifiers are set at the proper sensitivity level and the refueling crane is not over the reactor. Also the trips from the turbine control valves, turbine stop valves, main steam isolation valves, and condenser vacuum are bypassed. If the refueling crane is over the reactor, all rods must be fully inserted and none can be withdrawn.

3. Startup/Hot Standby - In this position, the reactor protection scram trips, initiated by condenser low vacuum and main steamline isolation valve closure, are bypassed, the low pressure main steam line isolation valve closure trip is bypassed, and the reactor protection system is energized, with IRM and APRM neutron monitoring system trips and control rod withdrawal interlocks in service.

4. Run - In this position the reactor is at or above 825 psig, and the reactor protection system is energized, with APRM protection and RBM interlocks in service (excluding the 15% high flux scram).

M. Operable - A system, subsystem, train, component, or device shall be operable when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electrical power sources, cooling or 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).

N. Operating - Operating means that a system, subsystem, train, component or device is performing its intended functions in its required manner.

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

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

1. All manual containment isolation valves on lines connecting to the reactor coolant system or containment which are not required to be open during accident conditions are closed.

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

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

4. All blind flanges and manways are closed.

Q. Protective Instrumentation Definitions

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

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

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

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

R. Rated Neutron Flux - Rated neutron flux is the neutron flux that corresponds to a steady-state power level of 2511 thermal megawatts.

S. Rated Thermal Power - Rated thermal power means a steady-state power level of 2511 thermal megawatts.

T. Reactor Power Operation - Reactor power operation is any operation with the mode switch in the Startup/Hot Standby or Run position with the reactor critical and above 1% rated thermal power.

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

V. Refueling Outage - Refueling outage is the period of time between the shutdown of the unit prior to a refueling and a startup of the plant subsequent to that refueling. 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 completion of the previous refueling outage, the required surveillance testing need not be performed until the next regularly scheduled outage.

W. Safety Limit - The safety limits are limits below which the reasonable maintenance of the cladding and primary system are assured. Exceeding such a limit is cause for unit shutdown, and review by the NRC before resumption of unit operation. Operation beyond such a limit may not in itself result in serious consequences, but it indicates an operational deficiency subject to regulatory review.

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

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

2. The standby gas treatment system is operable.

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

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

1. Hot Shutdown means conditions as above, with reactor coolant temperature greater than 212°F.

2. Cold Shutdown means conditions as above, with reactor coolant temperature equal to or less than 212°F.

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

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

BB. Critical Power Ratio (CPR) - The critical power ratio is the ratio of that assembly power which causes some point in the assembly to experience transition boiling to the assembly power at the reactor condition of interest as calculated by application of the GEXL correlation (reference NEDO-10958).

CC. Minimum Critical Power Ratio (MCPR) - The minimum incore critical power ratio corresponding to the most limiting fuel assembly in the core.

DD. Surveillance Interval - Each surveillance requirement shall be performed within the specified surveillance interval with:

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

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

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

FF. Maximum Fraction of Limiting Power Density (MFLPD) - The maximum fraction of limiting power density is the highest value existing in the core of the fraction of limiting power density (FLPD).

GG. Fraction of Rated Power (FRP) - The fraction of rated power is the ratio of core thermal power to rated thermal power of 2511 MWth.

HH. Reportable Event - Any of those conditions specified in Section 50.73 to 10CFR Part 50.

II. Dose Equivalent I-131 - That concentration of I-131 (microcurie/gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors For Power and Test Reactor Sites."

JJ. Process Control Program (PCP) - Contains the sampling, analysis, and formulation determination by which solidification of radioactive wastes from liquid systems is assured.

KK. Offsite Dose Calculation Manual (ODCM) - Contains the methodology and parameters used in the calculation of offsite doses due to radioactive gaseous and liquid effluents, and in the calculation of gaseous and liquid effluent monitor alarm/trip setpoints.

LL. Channel Functional Test (Radiation Monitor) - Shall be the injection of a simulated signal into the channel as close to the sensor as practicable to verify operability including alarm and/ or trip functions.

MM. Source Check - The qualitative assessment of instrument response when the sensor is exposed to a radioactive source.

NN. Member(s) of the Public - Shall include all persons who are not occupationally associated with the plant. This category does not include employees of the utility, its contractors, or vendors. Also excluded from this category are persons who enter the site to service equipment or to make deliveries. This category does include persons who use portions of the site for recreational, occupational, or other purposes not associated with the plant.

OO. Dual Loop Operation (DLO) - Reactor power operation with both recirculation pumps running.

PP. Single Loop Operation (SLO) - Reactor power operation with one recirculation pump running.

1.1/2.1 FUEL CLADDING INTEGRITY

SAFETY LIMIT

Applicability:

The safety limits established to preserve the fuel cladding integrity apply to those variables which monitor the fuel thermal behavior.

Objective:

The objective of the safety limits is to establish limits below which the integrity of the fuel cladding is preserved.

LIMITING SAFETY SYSTEM SETTING

Applicability:

The limiting safety system settings apply to trip settings of the instruments and devices which are provided to prevent the fuel cladding integrity safety limits from being exceeded.

Objective:

The objective of the limiting safety system settings is to define the level of the process variables at which automatic protective action is initiated to prevent the fuel cladding integrity safety limits from being exceeded.

SPECIFICATIONS

A. Reactor Pressure > 800 psig and Core Flow > 10% of Rated

The existence of a minimum critical power ratio (MCPR) less than 1.07 shall constitute violation of the fuel cladding integrity safety limit.

A. Neutron Flux Trip Settings

The limiting safety system trip settings shall be as specified below:

1. APRM Flux Scram Trip Setting (Run Mode)

When the reactor mode switch is in the Run position, the APRM flux scram setting shall be as shown in Figure 2.1-1 and shall be:

$S \leq (.58W_D + 62)$

with a maximum setpoint of 120% for core flow equal to 98 x 10^6 lb/hr and greater.

where

S = setting in percent of rated power

W_D = percent of drive flow required to produce a rated core flow of 98 million lb/hr. In the event of operation with a maximum fraction of limiting power density (MFLPD) greater than the fraction of rated power (FRP), the setting shall be modified as follows:

$$S \leq (.58W_D + 62) \left[\frac{FRP}{MFLPD} \right]$$

Where:

FRP = fraction of rated thermal power (2511 MW_t)

MFLPD = maximum fraction of limiting power density where the limiting power density for each bundle is the design linear heat generation rate for that bundle.

The ratio of FRP/MFLPD shall be set equal to 1.0 unless the actual operating value is less than 1.0 in which case the actual operating value will be used.

This adjustment may also be performed by increasing the APRM gain by the inverse ratio, MFLPD/FRP, which accomplishes the same degree of protection as reducing the trip setting by FRP/MFLPD.

2. APRM Flux Scram Trip Setting (Refueling or Startup and Hot Standby Mode)

When the reactor mode switch is in the Refuel or Startup Hot Standby position, the APRM scram shall be set at less than or equal to 15% of rated neutron flux.

3. IRM Flux Scram Trip Setting

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

4. When the reactor mode switch is in the Startup or Run position, the reactor shall not be operated in the natural circulation flow mode.

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

When the reactor pressure is $\leq$ 800 psig or core flow is less than 10% of rated, the core thermal power shall not exceed 25% of rated thermal power.

B. APRM Rod Block Setting

The APRM rod block setting shall be shown in Figure 2.1-1 and shall be :

$$S \leq (.58W_D + 50)$$

The definitions used above for the APRM scram trip apply. In the event of operation with a maximum fraction limiting power density (MFLPD) greater than the fraction of rated power (FRP), the setting shall be modified as follows:

$$S \leq (.58W_D + 50) \frac{FRP}{MFLPD}$$

The definitions used above for the APRM scram trip apply.

The ratio of FRP to MFLPD shall be set equal to 1.0 unless the actual operating value is less than 1.0, in which case the actual operating value will be used.

This may also be performed by increasing the APRM gain by the inverse ratio, MFLPD/FRP, which accomplishes the same degree of protection as reducing the trip setting by FRP/MFLPD.

C. Power Transient

1. The neutron flux shall not exceed the scram setting established in Specification 2.1.A for longer than 1.5 seconds as indicated by the process computer.

2. When the process computer is out of service, this safety limit shall be assumed to be exceeded if the neutron flux exceeds the scram setting established by Specification 2.1.A and a control rod scram does not occur.

D. Reactor Water Level (Shutdown Condition)

Whenever the reactor is in the shutdown condition with irradiated fuel in the reactor vessel, the water level shall not be less than that corresponding to 12 inches above the top of the active fuel* when it is seated in the core.

*Top of active fuel is defined to be 360 inches above vessel zero (See Bases 3.2).

C. Reactor low water level scram setting shall be 144 inches above the top of the active fuel* at normal operating conditions.

D. Reactor low water level ECCS initiation shall be 84 inches (+4 inches /-0 inch) above the top of the active fuel* at normal operating conditions.

E. Turbine stop valve scram shall be ≤ 10% valve closure from full open.

F. Turbine control valve fast closure scram shall initiate upon actuation of the fast closure solenoid valves which trip the turbine control valves.

G. Main steamline isolation valve closure scram shall be ≤ 10% valve closure from full open.

*Top of active fuel is defined to be 360 inches above vessel zero (See Bases 3.2).

H. Main steamline low-pressure initiation of main steamline isolation valve closure shall be $\geq$ 825 psig.

I. Turbine EHC control fluid low-pressure scram on loss of control oil pressure shall be set at greater than or equal to 900 psig.

J. Condenser low vacuum scram shall be set at $\geq$ 21 inches Hg vacuum.

1.1 SAFETY LIMIT BASIS

The fuel cladding integrity limit is set such that no calculated fuel damage would occur as a result of an abnormal operational transient. Because fuel damage is not directly observable, a step-back approach is used to establish a safety limit such that the minimum critical power ratio (MCPR) is no less than the fuel cladding integrity safety limit. MCPR > the fuel cladding integrity safety limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical boundaries which separate radioactive materials from the environs. The integrity of the fuel cladding is related to its relative freedom from perforations or cracking.

Although some corrosion or use-related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the protection system safety settings. 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 stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding safety limit is defined with margin to the conditions which would produce onset of transition boiling (MCPR of 1.0). These conditions represent a significant departure from the condition intended by design for planned operation. Therefore, the fuel cladding integrity safety limit is established such that no calculated fuel damage shall result from an abnormal operational transient. Basis of the values derived for this safety limit for each fuel type is documented in Reference 1.

A. Reactor Pressure > 800 psig and Core Flow > 10% of Rated

Onset of transition boiling results in a decrease in heat transfer from the cladding and therefore elevated cladding temperature and the possibility of cladding failure. However, the existence of critical power, or boiling transition is not a directly observable parameter in an operating reactor. Therefore, the margin to boiling transition is calculated from plant operating parameters such as core power, core flow, feedwater temperature, and core power distribution. The margin for each fuel assembly is characterized by the critical power ratio (CPR), which is the ratio of the bundle power which would produce onset of transition boiling divided by the actual bundle power. The minimum value of this ratio for any bundle in the core is the minimum critical power ratio (MCPR). It is assumed that the plant operation is controlled to the nominal protective setpoints via the instrumented variables (Figure 2.1-3).

The MCPR fuel cladding integrity safety limit has sufficient conservatism to assure that in the event of an abnormal operational transient initiated from the normal operation condition, more than 99.9% of the fuel rods in the core are expected to avoid boiling transition. The margin between MCPR of 1.0 (onset of transition boiling) and the safety limit, is derived from a detailed statistical analysis considering all of the uncertainties in monitoring the core operating state, including uncertainty in the boiling transition correlation (see e.g., Reference 1). Because the boiling transition correlation is based on a large quantity of full-scale data, there is a very high confidence that operation of a fuel assembly at the condition of MCPR = the fuel cladding integrity safety limit would not produce boiling transition.

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

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

In addition to the boiling transition limit (MCPR) operation is constrained to a maximum LHGR = 17.5kw/ft for 7 x 7 fuel and 13.4kW/ft for all 8 x 8 fuel types. This constraint is established by Specification 3.5.J. to provide adequate safety margin to 1% plastic strain for abnormal operating transients initiated from high power conditions. Specification 2.1.A.1 provides for equivalent safety margin for transients initiated from lower power conditions by adjusting the APRM flow-biased scram setting by the ratio of FRP/MFLPD.

Specification 3.5.J established the LHGR maximum which cannot be exceeded under steady power operation.

B. Core Thermal Power Limit (Reactor Pressure < 800 psia)

At pressures below 800 psia, the core elevation pressure drop (0 power, 0 flow) is greater than 4.56 psi. At low powers and flows this pressure differential is maintained in the bypass region of the core. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low powers and flows will

always be greater than 4.56 psi. Analyses show that with a flow of 28 x 10^3 lb/hr bundle flow, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.56 psi driving head will be greater than 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 Mwt. At 25% of rated thermal power, the peak powered bundle would have to be operating at 3.86 times the average powered bundle in order to achieve this bundle power. Thus, a core thermal power limit of 25% for reactor pressures below 800 psia is conservative.

C. Power Transient

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, which is 8 to 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. In addition, control rod scrams are such that for normal operating transients, the neutron flux transient is terminated before a significant increase in surface heat flux occurs. Control rod scram times are checked as required by Specification 4.3.C and the MCPR operating limit is modified as necessary per Specification 3.5.K.

Exceeding a neutron flux scram setting and a failure of the control rods to reduce flux to less than the scram setting within 1.5 seconds does not necessarily imply that fuel is damaged; however, for this specification, a safety limit violation will be assumed any time a neutron flux scram setting is exceeded for longer than 1.5 seconds.

If the scram occurs such that the neutron flux dwell time above the limiting safety system setting is less than 1.7 seconds, the safety limit will not be exceeded for normal turbine or generator trips, which are the most severe normal operating transients expected. These analyses show that even if the bypass system fails to operate, the design limit of MCPR = the fuel cladding integrity safety limit is not exceeded. Thus, use of a 1.5 second limit provides additional margin.

The computer provided has a sequence annuciation program which will indicate the sequence in which scrams occur, such as neutron flux, pressure, etc. This program also indicates when the scram setpoint is cleared. This will provide information on how long a scram condition exists and thus provide some measure of the energy added during a transient. Thus, computer information normally will be available for analyzing scrams; however, if the computer information should not be available for any scram analysis, Specification 1.1.C.2 will be relied on to determine if a safety limit has been violated.

During periods when the reactor is shut down, consideration must also be given to water level requirements due to the effect of decay heat. If reactor water level should drop below the top of the active fuel during this time, the ability to cool the core is reduced. This reduction in core-cooling capability could lead to elevated cladding temperatures and cladding perforation. The core will be cooled sufficiently to prevent cladding melting should the water level be reduced to two-thirds the core height. Establishment of the safety limit at 12 inches above the top of the fuel* provides adequate margin. This level will be continuously monitored whenever the recirculation pumps are not operating.

*Top of the active fuel is defined to be 360 inches above vessel zero (see Bases 3.2).

References

1. "Generic Reload Fuel Applications," NEDE-24011-P-A*.

*Approved revision number at time reload fuel analyses are performed.

2.1 LIMITING SAFETY SYSTEM SETTING BASES

The abnormal operational transients applicable to operation of the units have been analyzed throughout the spectrum of planned operating conditions in accordance with Regulatory Guide 1.49. In addition, 2511 MWt is the licensed maximum steady-state power level of the units. This maximum steady-state power level will never knowingly be exceeded.

Conservatism incorporated into the transient analysis is documented in References 1 and 2. Transient analyses are initiated at the conditions given in these References.

The scram delay time and rate of rod insertion allowed by the analyses are conservatively set equal to the longest delay and slowest insertion rate acceptable by technical specifications. The effects of scram worth, scram delay time, and rod insertion rate, all conservatively applied, are of greatest significance in the early portion of the negative reactivity insertion. The rapid insertion of negative reactivity is assured by the time requirements for 5% and 20% insertion. By the time the rods are 60% inserted, approximately 4 dollars of negative reactivity have been inserted, which strongly turns the transient and accomplishes the desired effect. The times for 50% and 90% insertion are given to assure proper completion of the expected performance in the earlier portion of the transient, and to establish the ultimate fully shutdown steady-state condition.

The MCPR operating limit is, however, adjusted to account for the statistical variation of measured scram times as discussed in Reference 2 and the bases of Specification 3.5.K.

Steady-state operation without forced recirculation will not be permitted except during startup testing. The analysis to support operation at various power and flow relationships has considered operation with either one or two recirculation pumps.

The bases for individual trip settings are discussed in the following paragraphs.

For analyses of the thermal consequences of the transients, the MCPR's stated in Paragraph 3.5.K as the limiting condition of operation bound those which are conservatively assumed to exist prior to initiation of the transients.

A. Neutron Flux Trip Settings

1. APRM Flux Scram Trip Setting (Run Mode)

The average power range monitoring (APRM) system, which is calibrated using heat balance data taken during steady-state conditions, reads in percent of rated thermal power. Because fission chambers provide the basis input signals, the APRM system responds directly to average neutron flux. During transients the instantaneous rate of heat transfer from the fuel (reactor thermal power) is less than the instantaneous neutron flux due to the time constant of the fuel.

Therefore, during abnormal operational transients, the thermal power of the fuel will be less than that indicated by the neutron flux at the scram setting. Analyses demonstrate that with a 120% scram trip setting, none of the abnormal operational transients analyzed violates the fuel safety limit, and there is a substantial margin from fuel damage. Therefore, the use of flow-referenced scram trip provides even additional margin.

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

The scram trip setting must be adjusted to ensure that the LHGR transient peak is not increased for any combination of maximum fraction of limiting power density (MFLPD) and reactor core thermal power. The scram setting is adjusted in accordance with the formula in Specification 2.1.A.1 when the MFLPD is greater than the fraction of rated power (FRP). The adjustment may be accomplished by increasing the APRM gain by the reciprocal of FRP/MFLPD. This provides the same degree of protection as reducing the trip settings by FRP/MFLPD by raising the initial APRM readings closer to the trip settings such that a scram would be received at the same point in a transient as if the trip settings had been reduced by $\frac{FRP}{MFLPD}$.

2. APRM Flux Scram Trip Setting (Refuel or Startup/Hot Standby Mode)

For operation in the Startup mode while the reactor is at low pressure, the APRM scram setting of 15% of rated power provides adequate thermal margin between the setpoint and the safety limit, 25% of rated. The margin is adequate to accomodate anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor, cold water from sources available during startup is not much colder than that already in the system, temperature coefficients are small, and control rod patterns are constrained to be uniform by operating procedures backed up by the rod worth minimizer. 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 power, the rate of power rise is very slow. Generally, the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the scram level, the rate of power rises no more than 5% of rated power per minute, and the APRM system would be more than adequate to assure a scram before the power could exceed the safety limit. The 15% APRM scram remains active until the mode switch is placed in the Run position. This switch occurs when reactor pressure is greater than 825 psig.

3. IRM Flux Scram Trip Setting

The IRM system consists of eight chambers, four in each of the reactor protection system low channels. The IRM is a 5-decade instrument which covers the range of power level between that covered by the SRM and the APRM. The 5 decades are broken down into 10 ranges, each being one-half a decade in size.

The IRM scram trip setting of 120 divisions is active in each range of the IRM. For example, if the instrument were on Range 1, the scram setting would be 120 divisions for that range; likewise, if the instrument were on Range 5, the scram would be 120 divisions on that range. Thus, as the IRM is ranged up to accomodate the increase in power level, the scram trip setting is also ranged up.

The most significant sources of reactivity change during the power increase are due to control rod withdrawal. In order to ensure that the IRM provides adequate protection against the single rod withdrawal error, a range of rod withdrawal accidents was analyzed. This analysis included starting the accident at various power levels. The most severe case involves an initial condition in which the reactor is just subcritical and the IRM system is not yet on scale.

4 Additional conservatism was taken in this analysis by assuming that the IRM channel closest to the withdrawn rod is bypassed. The results of this analysis show that the reactor is scrammed and peak power limited to 1% of rated power, thus maintaining MCPR above the fuel cladding integrity safety limit. Based on the above analysis, the IRM provides protection against local control rod withdrawal errors and continuous withdrawal of control rods in sequence provides backup protection for the APRM.

B. APRM Rod Block Trip Setting

Reactor power level may be varied by removing control rods or by varying the recirculation flow rate. The APRM system provides a control rod block to prevent gross rod withdrawal at constant recirculation flow rate to protect against grossly exceeding the MCPR Fuel Cladding Integrity Safety Limit. This rod block trip setting, which is automatically varied with recirculation loop flow rate, prevents an increase in the reactor power level to excessive values due to control rod withdrawal. The flow variable trip setting provides substantial margin from fuel damage, assuming a steady-state operation at the trip setting, over the entire recirculation flow range. The margin to the safety limit increases as the flow decreases for the specified trip setting versus flow relationship; therefore, the worst-case MCPR which could occur during steady-state operation is at

108% of rated thermal power because of the APRM rod block trip setting. The actual power distribution in the core is established by specified control rod sequences, and is monitored continuously by the incore LPRM system. As with APRM scram trip setting, the APRM rod block trip setting is adjusted downward if the maximum fraction of limiting power density exceeds the fraction of rated power, thus preserving the APRM rod block safety margin.

C. Reactor Low Water Level Scram

The reactor low water level scram is set at a point which will assure that the water level used in the bases for the safety limit is maintained. The scram setpoint is based on normal operating temperature and pressure conditions because the level instrumentation is density compensated.

D. Reactor Low Low Water Level ECCS Initiation Trip Point

The emergency core cooling subsystems are designed to provide sufficient cooling to the core to dissipate the energy associated with the loss-of-coolant accident and to limit fuel cladding temperature to well below the cladding melting temperature to assure that core geometry remains intact and to limit any cladding metal-water reaction to less than 1%. To accomplish their intended function, the capacity of each emergency core cooling system component was established based on the reactor low water level scram setpoint. To lower the setpoint of the low water level scram would increase the capacity requirement for each of the ECCS components. Thus, the reactor vessel low water level scram was set low enough to permit margin for operation, yet will not be set lower because of ECCS capacity requirements.

The design of the ECCS components to meet the above criteria was dependent on three previously set parameters: the maximum break size, the low water level scram setpoint, and the ECCS initiation setpoint. To lower the setpoint for initiation of the ECCS could lead to a loss of effective core cooling. To raise the ECCS initiation setpoint would be in a safe direction, but it would reduce the margin established to prevent actuation of the ECCS during normal operation or during normally expected transients.

E. Turbine Stop Valve Scram

The turbine stop valve closure scram trip anticipates the pressure, neutron flux, and the heat flux increase that could result from rapid closure of the turbine stop valves. With a scram trip setting of 10% of valve closure from full open, the resultant increase in surface heat flux is limited such that MCPR remains above the MCPR fuel cladding integrity safety limit even during the worst-case transient that assumes the turbine bypass is closed.

F. Turbine Control Valve Fast Closure Scram

The turbine control valve fast closure scram is provided to anticipate the rapid increase in pressure and neutron flux resulting from fast closure of the turbine control valves due to a load rejection and subsequent failure of the bypass, i.e., it prevents MCPR from becoming less than the MCPR fuel cladding integrity safety limit for this transient. For the load rejection without bypass transient from 100% power, the peak heat flux (and therefore LHGR) increases on the order of 15% which provides wide margin to the value corresponding to 1% plastic strain of the cladding.

G. Reactor Coolant Low Pressure Initiates Main Steam Isolation Valve Closure

The low pressure isolation at 825 psig was provided to give protection against fast reactor depressurization and the resulting rapid cooldown of the vessel. Advantage was taken of the scram feature which occurs in the Run mode when the main steamline isolation valves are closed to provide for reactor shutdown so that operation at pressures lower than those specified in the thermal hydraulic safety limit does not occur, although operation at a pressure lower than 825 psig would not necessarily constitute an unsafe condition.

H. Main Steamline Isolation Valve Closure Scram

The low pressure isolation of the main steamlines at 825 psig was provided to give protection against rapid reactor depressurization and the resulting rapid cooldown of the vessel. Advantage was taken of the scram feature in the Run mode which occurs when the main steamline isolation valves are closed to provide for reactor shutdown so that high power operation at low reactor pressures does not occur, thus providing protection for the fuel cladding integrity safety limit. Operation of the reactor at pressures lower than 825 psig requires that the reactor mode switch be in the Startup position, where protection of the fuel cladding integrity safety limit is provided by the IRM and APRM high neutron flux scrams. Thus, the combination of main steamline low-pressure isolation and isolation valve closure scram in the Run mode assures the availability of neutron flux scram protection over the entire range of applicability of fuel cladding integrity safety limit. In addition, the isolation valve closure scram in the Run mode anticipates the pressure and flux transients which occur during normal or inadvertent isolation valve closure. With the scrams set at 10% valve closure in the Run mode, there is no increase in neutron flux.

I. Turbine EHC Control Fluid Low-Pressure Scram

The turbine EHC control system operates using high pressure oil. There are several points in this oil system where a loss of oil pressure could result in a fast closure of the turbine control valves. This fast closure of the turbine control valves is not protected by the turbine control valve fast closure scram, since failure of the oil system would not result in the fast closure solenoid valves being actuated. For a turbine control valve fast closure, the core would be protected by the APRM and high-reactor pressure scrams. However, to provide the same margins as provided for the generator load rejection on fast closure of the turbine control valves, a scram has been added to the reactor protection system which senses failure of control oil pressure to the turbine control system. This is an anticipatory scram and results in reactor shutdown before any significant increase in neutron flux occurs. The transient response is very similar to that resulting from the turbine control valve fast closure scram. The scram setpoint of 900 psig is set high enough to provide the necessary anticipatory function and low enough to minimize the number of spurious scrams. Normal operating pressure for this system is 1250 psig. Finally, the control valves will not start until the fluid pressure is 600 psig. Therefore, the scram occurs well before valve closure begins.

J. Condenser Low Vacuum Scram

Loss of condenser vacuum occurs when the condenser can no longer handle the heat input. Loss of condenser vacuum initiates a closure of the turbine stop valves and turbine bypass valves which eliminates the heat input to the condenser. Closure of the turbine stop and bypass valves causes a pressure transient, neutron flux rise and an increase in surface heat flux. To prevent the cladding safety limit from being exceeded if this occurs, a reactor scram occurs on turbine stop valve closure in the Run mode. The turbine stop valve closure scram function alone is adequate to prevent the cladding safety limit from being exceeded in the event of a turbine trip transient with bypass closure. The condenser low vacuum scram is anticipatory to the stop valve closure scram and causes a scram before the stop valves are closed and thus the resulting transient is less severe. Scram occurs in the Run mode at 21-inch Hg vacuum, stop valve closure occurs at 20-inch Hg vacuum, and bypass closure at 7-inch Hg vacuum.

References

1. "Generic Reload Fuel Application," NEDE-24011-P-A.*

*Approved revision number at time reload analyses are performed.

2. "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors", General Electric Co. licensing Topical Report NEDO 24154 Vols. I and II and NEDE-24154 Volume III as supplemented by letter dated September 5, 1980 from R.H. Buchholz (GE) to P.S. Check (NRC).

APRM Flow Reference Scram
and APRM Rod Block Settings

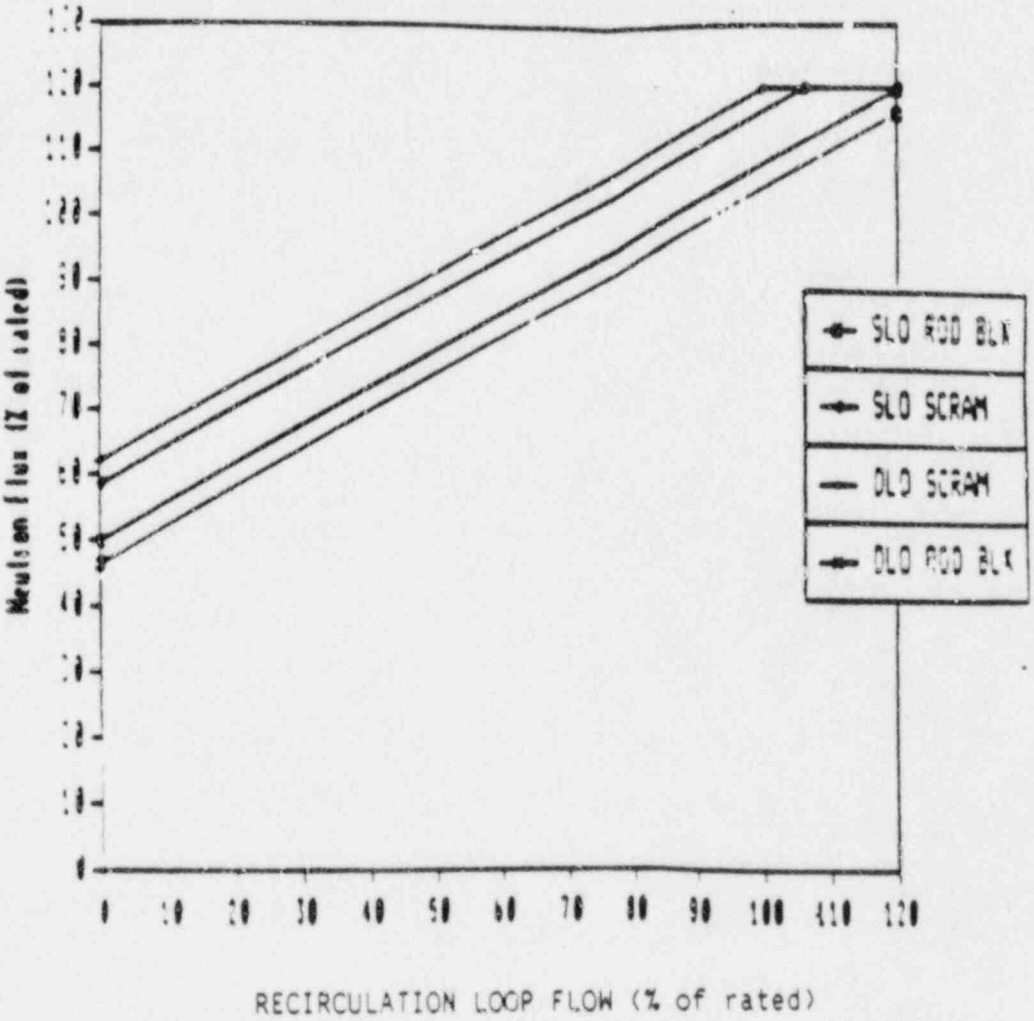


FIGURE 2.1-1

Figure 2.1-2 has been deleted.

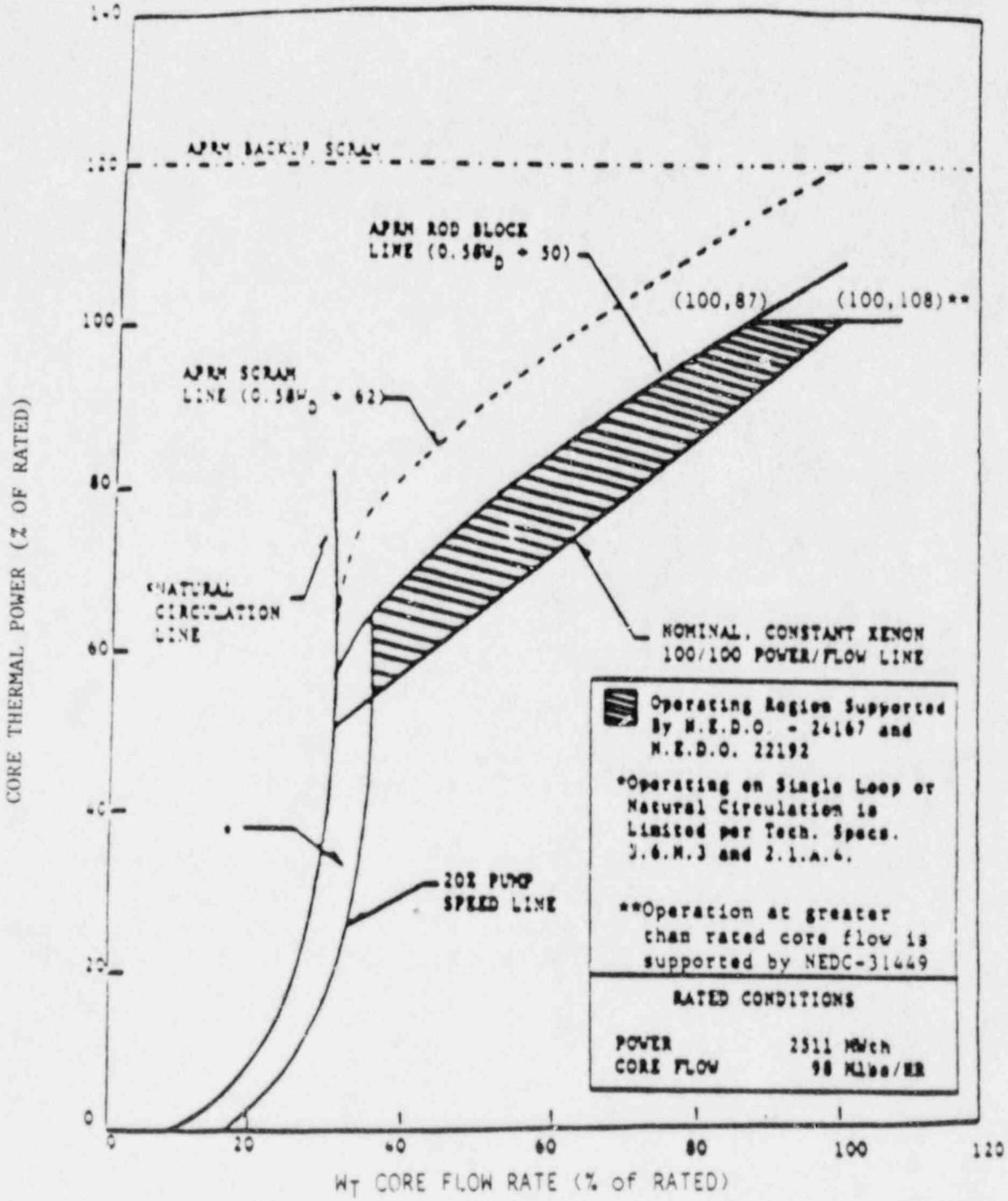


Figure 2.1-3
(SCHEMATIC)

APRM FLOW BIAS SCRAM RELATIONSHIP
TO NORMAL OPERATING CONDITIONS

1.2/2.2 REACTOR COOLANT SYSTEM

SAFETY LIMIT

Applicability:

Applies to limits on reactor coolant system pressure.

Objective:

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

LIMITING SAFETY SYSTEM SETTING

Applicability:

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

Objective:

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

SPECIFICATIONS

A. The reactor coolant system pressure as measured by the vessel steam space pressure indicator shall not exceed 1345 PSIG at any time when irradiated fuel is present in the reactor vessel.

A. Reactor coolant high-pressure scram shall be at $\leq$1060 psig.

B. Primary system safety valve nominal settings shall be as follows:

1 valve at 1135 psig[1]
2 valves at 1240 psig
2 valves at 1250 psig
4 valves at 1260 psig

[1] Target Rock combination safety/relief valve

The allowable setpoint error for each valve shall be at $\pm$1%.

1.2 SAFETY LIMIT BASES

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

The pressure safety limit 1345 psig as measured by the vessel steam space pressure indicator is equivalent to 1375 psig at the lowest elevation of the reactor vessel. The 1375 psig value is derived from the design pressures of the reactor pressure vessel and coolant system piping. The respective design pressures are 1250 psig at 575°F and 1175 at 560°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 III for the pressure vessel, and USASI B31.1 Code for the reactor coolant system piping. The ASME Boiler and Pressure Vessel Code permits pressure transients up to 10% over design pressure (110% x 1250 = 1375 psig), and the USASI Code permits pressure transients up to 20% over design pressure (120% x 1175 = 1410 psig). The safety limit pressure of 1375 psig is referenced to the lowest elevation of the reactor vessel. The design pressure for the recirc. suction line piping (1175 psig) was chosen relative to the reactor vessel design pressure. Demonstrating compliance of peak vessel pressure with the ASME overpressure protection limit (1375 psig) assures compliance of the suction piping with the USASI limit (1410 psig). Evaluation methodology to assure that this safety limit pressure is not exceeded for any reload is documented in Reference 1. 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 26,700 psi at an internal pressure of 1250 psig; this is a factor of 1.5 below the yield strength of 40,100 psi at 575°F. At the pressure limit of 1375 psig, the general membrane stress will only be 29,400 psi, still safely below the yield strength.

The relationships of stress levels to yield strength are comparable for the primary system piping and provide similar margin of protection at the established safety pressure limit.

The normal operating pressure reactor coolant system is 1000 psig. For the turbine trip or loss of electrical load transients, the turbine trip scram or generator load rejection scram together with the turbine bypass system limits pressure to approximately 1100 psig (References 2, 3, and 4). In addition, pressure relief valves have been provided to reduce the probability of the safety valves operating in the event that the turbine bypass should fail.

Finally, the safety valves are sized to keep the reactor vessel peak pressure below 1375 psig with no credit taken for relief valves during the postulated full closure of all MSIVs without direct (valve position switch) scram. Credit is taken for the neutron flux scram, however. The indirect flux scram and safety valve actuation, provide adequate margin below the allowable peak vessel pressure of 1375 psig.

Reactor pressure is continuously monitored in the control room during operation on a 1500 psi full-scale pressure recorder.

References

1. "Generic Reload Fuel Application," NEDE-24011-P-A*

2. SAR, Section 11.22

3. Quad Cities 1 Nuclear Power Station first reload license submittal, Section 6.2.4.2, February 1974.

4. GE Topical Report NEDO-20693, General Electric Boiling Water Reactor No. 1 Licensing submittal for Quad Cities Nuclear Power Station Unit 2, December 1974.

* Approved revision number at time reload analyses are performed.

2.2 LIMITING SAFETY SYSTEM SETTING BASES

In compliance with Section III of the ASME Code, the safety valves must be set to open at no higher than 103% of design pressure, and they must limit the reactor pressure to no more than 110% of design pressure. Both the high neutron flux scram and safety valve actuation are required to prevent overpressurizing the reactor pressure vessel and thus exceeding the pressure safety limit. The pressure scram is available as backup protection to the high flux scram. Analyses are performed as described in the "Generic Reload Fuel Application," NEDE-24011-P-A (approved revision number at time reload analyses are performed) for each reload to assure that the pressure safety limit is not exceeded. If the high-flux scram were to fail, a high-pressure scram would occur at 1060 psig.

3.0/4.0 Limiting Conditions for Operation
(General)

Applicability:

Applies to systems, subsystems, trains, components, or devices required to be operable.

Objective:

To assure that no set of equipment outages would be allowed to persist that would result in the facility being in an unprotected condition.

LIMITING CONDITION FOR OPERATION

A. In the event a Limiting Condition for Operation cannot be satisfied because of circumstances in excess of those addressed in the specification, the unit shall be placed in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours unless corrective measures are completed that satisfy the Limiting Conditions for Operation.

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 its applicable Limiting Condition for Operation, provided:

   1. Its corresponding normal or emergency power source is OPERABLE, and

   2. All of its redundant systems, subsystems, trains, components, and devices in the other division are OPERABLE, or likewise satisfy the requirements of this specification.

   Unless both conditions 1. and 2. are satisfied, the unit shall be placed in at least HOT SHUTDOWN within 12 hours and in at least COLD SHUTDOWN within the following 24 hours.

C. Specifications 3.0.A and 3.0.B are not applicable in refueling or cold shutdown.

3.0/4.0 BASES

3.0.A

This specification delineates the action to be taken for circumstances not directly provided for in the Limiting Condition for Operation statements and whose occurrence would violate the intent of the specification.

3.0.B

This specification delineates what additional conditions must be satisfied to permit operation to continue, consistent with the Limiting Condition for Operation statements for power sources, when a normal or emergency power source is not OPERABLE. It specifically prohibits operation when one division is inoperable because its normal or emergency power source is inoperable and a system, subsystem, train, component, or device in another division is inoperable for another reason. Power sources are defined as AC Auxiliary Electrical Systems as noted in Section 3.9.A.1, 3.9.A.2, and 3.9.A.3.

The provisions of this specification permit the Limiting Condition for Operation statements associated with individual systems, subsystems, trains, components, or devices to be consistent with the Limiting Condition for Operation statements of the associated electrical power source. It allows operation to be governed by the time limits of the action statements associated with the Limiting Condition for Operation for the normal or emergency power source, not the individual action statements 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.

3.1/4.1 REACTOR PROTECTION SYSTEM

LIMITING CONDITIONS FOR OPERATION

Applicability:

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

Objective:

To assure the operability of the reactor protection system.

SURVEILLANCE REQUIREMENTS

Applicability:

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

Objective:

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

SPECIFICATIONS

A. The setpoints, minimum number of trip systems, and minimum number of instrument channels that must be operable for each position of the reactor mode switch shall be as given in Tables 3.1-1 through 3.1-4. The system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds.

B. If, during operation, the maximum fraction of limiting power density exceeds the fraction of rated power when operating above 25% rated thermal power, either:

1. the APRM scram and rod block settings shall be reduced to the values given by the equations in Specification 2.1.A.1 and 2.1.B. This may also be accomplished by increasing the APRM gain as described therein.

A. Instrumentation systems shall be functionally tested and calibrated as indicated in Tables 4.1-1 and 4.1-2 respectively.

B. Daily during reactor power operation, the core power distribution shall be checked for maximum fraction of limiting power density (MFLPD) and compared with the fraction of rated power (FRP) when operating above 25% rated thermal power.

2. the power distribution shall be changed such that the maximum fraction of limiting power density no longer exceeds the fraction of rated power.

C. When it is determined that a channel is failed in the unsafe condition and Column 1 of Tables 3.1-1 through 3.1-3 cannot be met, that trip system must be put in the tripped condition immediately. All other RPS channels that monitor the same variable shall be functionally tested within 8 hours. The trip system with the failed channel may be untripped for a period of time not to exceed 1 hour to conduct this testing. As long as the trip system with the failed channel contains at least one operable channel monitoring that same variable, that trip system may be placed in the untripped position for short periods of time to allow functional testing of all RPS instrument channels as specified by Table 4.1-1. The trip system may be in the untripped position for no more than 8 hours per functional test period for this testing.

3.1 LIMITING CONDITIONS FOR OPERATION BASES

The reactor protection system automatically initiates a reactor scram to:

a. preserve the integrity of the fuel cladding

b. preserve the integrity of the primary system, and

c. minimize the energy which must be absorbed and prevent criticality following a loss-of-coolant accident.

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

The reactor protection system is of the dual channel type (reference SAR Section 7.7.1.2) The system is made up of two independent trip systems, each having two subchannels of tripping devices. Each subchannel has an input from at least one instrument channel which monitors a critical parameter.

The outputs of the subchannels are combined in a one-out-of-two-logic; i.e., an input signal on either one or both of the subchannels will cause a trip system trip. The outputs of the trip systems are arranged so that a trip on both systems is required to produce a reactor scram.

This system meets the requirements of the IEEE 279 Standard for Nuclear Power Plant Protection Systems issued September 13, 1966. The system has a reliability greater than that of a two-out-of-three system and somewhat less than that of a one-out-of-two system (reference APED 5179).

With the exception of the average power range monitor (APRM) and intermediate range monitor (IRM) channels, each subchannel has one instrument channel. When the minimum condition for operation on the number of operable instrument channels per untripped protection trip system is met, or if it cannot be met and the affected protection trip system is placed in a tripped condition, the effectiveness of the protection system is preserved, i.e., the system can tolerate a single failure and still perform its intended function of scramming the reactor. Three APRM instrument channels are provided for each protection trip system.

APRM's # 1 and # 3 operate contacts in one subchannel and APRM's # 2 and #3 operate contacts in the other subchannel. APRM's # 4, # 5 and # 6 are arranged similarly in the other protection trip system. Each protection trip system has one more APRM than is necessary to meet the minimum number required per channel. This allows the bypassing of one APRM per protection trip system for maintenance, testing, or calibration. Additional IRM channels have also been provided to allow for bypassing of one such channel. The bases for the scram settings for the IRM, APRM, high reactor pressure, reactor low water level, turbine control valve fast closure, and turbine stop valve closure are discussed in Specifications 2.1 and 2.2.

Pressure sensing of the drywell is provided to detect a loss-of-coolant accident and initiate the emergency core cooling equipment. The pressure-sensing instrumentation is a backup to the water-level instrumentation which is discussed in Specification 2.1. A scram is provided at the same setting as the emergency core cooling system (ECCS) initiation to minimize the energy which must be accommodated during a loss-of-coolant accident and to prevent the reactor from going critical following the accident.

The control rod drive scram system is designed so that all of the water which is discharged from the Reactor by a scram can be accommodated in the discharge piping. A part of this system is an individual instrument volume for each of the south and north CRD accumulators. These two volumes and their piping can hold in excess of 90 gallons of water and is the low point in the piping. No credit was taken for these volumes in the design of the discharge piping relative to the amount of water which must be accommodated during a scram. During normal operations, the discharge volumes are empty; however, should either volume fill with water, the water discharged to the piping from the Reactor may not be accommodated which could result in slow scram times or partial or no control rod insertion. To preclude this occurrence, level switches have been installed in both volumes which will alarm and scram the Reactor when the volume remaining in either instrument volume is approximately 40 gallons. For diversity of level sensing methods that will ensure and provide a scram, both differential pressure switches and thermal switches have been incorporated into the design and logic of the system. The setpoint for the scram signal has been chosen on the basis of providing sufficient volume remaining to accommodate a scram even with 5 gpm leakage per drive into the SDV. As indicated above, there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or the amount of insertion of the control rods. This function shuts the Reactor down while sufficient volume remains to accommodate the discharged water and precludes the situation in which a scram would be required but not be able to perform its function properly.

Loss of condenser vacuum occurs when the condenser can no longer handle heat input. Loss of condenser vacuum initiates a closure of the turbine stop valves and turbine bypass valves which eliminates the heat input to the condenser. Closure of the turbine stop and bypass valves causes a pressure transient, neutron flux rise, and an increase in surface heat flux. To prevent the cladding safety limit from being exceeded if this occurs, a reactor scram occurs on turbine stop valve closure. The turbine stop valve closure scram function alone is adequate to prevent the cladding safety limit from being exceeded in the event of a turbine trip transient with bypass closure.

The condenser low-vacuum scram is a backup to the stop valve closure scram and causes a scram before the stop valves are closed, thus the resulting transient is less severe. Scram occurs at 21 inches Hg vacuum, stop valve closure occurs at 20 inches Hg vacuum, and bypass closure at 7 inches Hg vacuum.

High radiation levels in the main steamline tunnel above that due to the normal nitrogen and oxygen radioactivity are an indication of leaking fuel. A scram is initiated whenever such radiation level exceeds seven times normal background. The purpose of this scram is to reduce the source of such radiation to the extent necessary to prevent excessive turbine contamination. Discharge of excessive amounts of radioactivity to the site environs is prevented by the air ejector off-gas monitors, which cause an isolation of the main condenser off-gas line provided the limit specified in Specification 3.8 is exceeded.

The main steamline isolation valve closure scram is set to scram when the isolation valves are 10% closed from full open. This scram anticipates the pressure and flux transient which would occur when the valves close. By scramming at this setting, the resultant transient is insignificant.

A reactor mode switch is provided which actuates or bypasses the various scram functions appropriate to the particular plant operating status (reference SAR Section 7.7.1.2). Whenever the reactor mode switch is in the Refuel or Startup/Hot Standby position, the turbine condenser low-vacuum scram and main steamline isolation valve closure scram are bypassed. This bypass has been provided for flexibility during startup and to allow repairs to be made to the turbine condenser. While this bypass is in effect, protection is provided against pressure or flux increases by the high-pressure scram and APRM 15% scram, respectively, which are effective in this mode.

If the reactor were brought to a hot standby condition for repairs to the turbine condenser, the main steamline isolation valves would be closed. No hypothesized single failure or single operator action in this mode of operation can result in an unreviewed radiological release.

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

The IRM system provides protection against excessive power levels and short reactor periods in the startup and intermediate power ranges (reference SAR Sections 7.4.4.2 and 7.4.4.3). A source range monitor (SRM) system is also provided to supply additional neutron level information during startup but has no scram functions (reference SAR Section 7.4.3.2). Thus the IRM is required in the Refuel and Startup/Hot Standby modes. In addition, protection is provided in this range by the APRM 15% scram as discussed in the bases for Specification 2.1. In the power range, the APRM system provides required protection (reference SAR Section 7.4.5.2). Thus, the IRM system is not required in the Run mode, the APRM's cover only the intermediate and power range; the IRM's provide adequate coverage in the startup and intermediate range.

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

The turbine condenser low-vacuum scram is required only during power operation and must be bypassed to start up the unit.

The requirement that the IRM's be inserted in the core when the APRM's read 3/125 of full scale assures that there is proper overlap in the neutron-monitoring systems and thus that adequate coverage is provided for all ranges of reactor operation.

4.1 SURVEILLANCE REQUIREMENTS BASES

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

The channels listed in Table 4.1-1 and 4.1-2 are divided into three groups respecting functional testing.

These are:

1. on-off sensors that provide a scram trip function (Group 1);

2. analog devices coupled with bistable trips that provide a scram function (Group 2); and,

3. devices which serve a useful function only during some restricted mode of operation, such as Startup/Hot Standby, Refuel, or Shutdown, or for which the only practical test is one that can be performed at shutdown (Group 3).

The sensors that make up Group 1 are specifically selected from among the whole family of industrial on-off sensors that have earned an excellent reputation for reliable operation. Actual history on this class of sensors operating in nuclear power plants shows four failures in 472 sensor years, or a failure rate of 0.97×10^{-6}/hr. During design a goal of 0.99999 probability of success (at the 50% confidence level) was adopted to assure that a balanced and adequate design is achieved. The probability of success is primarily a function of the sensor failure rate and the test interval. A 3-month test interval was planned for Group 1 sensors. This is in keeping with good operating practice and satisfies the design goal for the logic configuration utilized in the reactor protection system.

To satisfy the long-term objective of maintaining an adequate level of safety throughout the plant lifetime, a minimum goal of 0.9999 at the 95% confidence level is proposed. With the one-out-of-two taken twice logic, this requires that each sensor have an availability of 0.993 at the 95% confidence level. This level of availability may be maintained by adjusting the test interval as a function of the observed failure history (Reference 1). To facilitate the implementation of this technique, Figure 4.1-1 is provided to indicate an appropriate trend in test interval. The procedure is as follows:

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

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

3. The accumulated number of unsafe failures is plotted as an ordinate against M as an abscissa on Figure 4.1-1.

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

5. A test interval of 1 month will be used initially until a trend is established.

Group 2 devices utilize an analog sensor followed by an amplifier and a bistable trip circuit. The sensor and amplifier are active components, and a failure is almost always accompanied by an alarm and an indication of the source of trouble. In the event of failure, repair or substitution can start immediately. An as-is failure is one that "sticks" midscale and is not capable of going either up or down in response to an out-of-limits input. This type of failure for analog devices is a rare occurrence and is detectable by an operator who observes that one signal does not track the other three. For purposes of analysis, it is assumed that this rare failure will be detected within 2 hours.

The bistable trip circuit which is a part of the Group 2 devices can sustain unsafe failures which are revealed only on test. Therefore, it is necessary to test them periodically.

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

The bistable devices are monitored during plant operation to record their failure history and establish a test interval using the curve of Figure 4.1-1. There are numerous identical bistable devices used throughout the plant instrumentation system. Therefore, significant data on the failure rates for the bistable devices should be accumulated rapidly.

The frequency of calibration of the APRM flow biasing network has been established at each refueling outage. The flow biasing network is functionally tested at least once per month and, in addition, cross calibration checks of the flow input to the flow-biasing network can be made during the functional test by direct meter reading (IEEE 279 Standard for Nuclear Power Plant Protection Systems, Section 4.9, September 13, 1966). There are several instruments which must be calibrated, and it will take several days to perform the calibration of the entire network. While the calibration is being performed, a zero flow signal will be sent to half of the APRM's resulting in a half scram and rod block condition. Thus, if the calibration were performed during operation, flux shaping would not be possible. Based on experience at other generating stations drift of instrument such as those in the flow biasing network is not significant, therefore, to avoid spurious scrams, a calibration frequency of each refueling outage is established.

Reactor low water level instruments 1-263-57A, 1-263-57B, 1-263-58A, and 1-263-58B have been modified to be an analog trip system. The analog trip system consists of an analog sensor (transmitter) and a master/slave trip unit setup which ultimately drives a trip relay. The frequency of calibration and functional testing for instrument loops of the analog trip system, including reactor low water level, has been established in Licensing Topical Report NEDO-21617-A (December 1978). With the one-out-of-two-taken-twice logic, NEDO-21617-A states that each trip unit be subjected to a calibration/functional test of one month. An adequate calibration/surveillance test interval for the transmitter is once per operating cycle.

Group 3 devices are active only during a given portion of the operation cycle. For example, the IRM is active during startup and inactive during full-power operation. Thus, the only test that is meaningful is the one performed just prior to shutdown or startup, i.e., the tests that are performed just prior to use of the instrument.

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

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

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

Experience with passive type instruments in Commonwealth Edison generating stations and substations indicate that the specified calibrations are adequate. For those devices which employ amplifiers, etc. drift specifications call for drift to be less than 0.4%/month i.e., in the period of a month a drift of 0.4% would occur, thus providing for adequate margin.

The sensitivity of LPRM detectors decreases with exposure to neutron flux at a slow and approximately constant rate. Changes in a power distribution and electronic drift also require compensation. This compensation is accomplished by calibrating the APRM system every 7 days using heat balance data by calibrating individual LPRM's at least every 1000 equivalent full-power hours using TIP traverse data. Calibration on this frequency assures plant operation at or below thermal limits.

A comparison of Tables 4.1-1 and 4.1-2 indicates that some instrument channels have not been included in the latter table. These are mode switch in shutdown, manual scram, high water level in scram discharge volume, main steamline isolation valve closure, turbine control valve fast closure, and turbine stop valve closure. All of the devices or sensors associated with these scram functions are simple on-off switches, hence calibration is not applicable, i.e., the switch is either on or off. Further, these switches are mounted solidly to the device and have a very low probability of moving; e.g., the thermal switches in the scram discharge volume tank. Based on the above, no calibration is required for these instrument channels.

B. The MFLPD shall be checked once per day to determine if the APRM scram requires adjustment. This may normally be done by checking the LPRM readings, TIP traces, or process computer calculations. Only a small number of control rods are moved daily, thus the peaking factors are not expected to change significantly and a daily check of the MFLPD is adequate.

References

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

2. Licensing Topical Report NEDO-21617-A (December 1978).

TABLE 3.1-1

REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENTS REFUEL MODE

Minimum Number of Operable or Tripped Instrument Channels per Trip System(1)	Trip Function	Trip Level Setting	Action(2)
1	Mode switch in shutdown		A
1	Manual scram		A
3	IRM High Flux	≤ 120/125 of full scale	A
3	Inoperative		A
	APRM(3)		
2	High Flux (15% scram)	Specification 2.1.A.2	A
2	Inoperative		A
2 (per bank)	High water level in scram discharge volume(4)	≤ 40 gallons per bank	A
2	High reactor pressure	≤ 1060 psig	A
2	High drywell pressure (5)	≤ 2.5 psig	A
2	Reactor low water level	≥ 8 inches(8)	A
2	Turbine condenser low vacuum (7)	≥ 21 inches Hg vacuum	A
2	Main steamline high radiation (12)	≤ 7 X normal full power background	A
4	Main steamline isolation valve closure (7)	≤ 10% valve closure	A

TABLE 3.1-2

REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENTS STARTUP/HOT STANDBY MODE

Minimum Number of Operable or Tripped Instrument Channels per Trip System(1)	Trip Function	Trip Level Setting	Action(2)
1	Mode switch in shutdown		A
1	Manual scram		A
	IRM		
3	High Flux	≤ 120/125 of full scale	A
3	Inoperative		A
	APRM(3)		
2	High Flux (15% scram)	Specification 2.1.A.2	A
2	Inoperative		A
2	High-reactor pressure	≤ 1060 psig	A
2	High drywell pressure (5)	≤ 2.5 psig	A
2	Reactor low water level	≥ 8 inches(8)	A
2 (per bank)	High water level in scram discharge volume(4)	≤ 40 gallons per bank	A
2	Turbine condenser low vacuum (7)	≥ 21 inches Hg vacuum	A
2	Main steamline high radiation (12)	≤ 7 X normal full power background	A
4	Main steamline isolation valve closure (7)	≤ 10% valve closure	A

TABLE 3.1-3

REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENTS RUN MODE

Minimum Number of Operable or Tripped Instrument Channels per Trip System(1)	Trip Function	Trip Level Setting	Action(2)
1	Mode switch in shutdown		A
1	Manual scram		A
	APRM(3)		
2	High Flux (flow biased)	Specification 2.1.A.1	A or B
2	Inoperative		A or B
2	Downscale (11)	≥ 3/125 of full scale	A or B
2	High-reactor pressure	≤ 1060 psig	A
2	High drywell pressure	≤ 2.5 psig	A
2	Reactor low water level	≥ 8 inches(8)	A
2 (per bank)	High-water level in scram discharge volume	≤ 40 gallons per bank	A
2	Turbine condenser low vacuum	≥ 21 inches Hg vacuum	A or C
2	Main Steamline high radiation (12)	≤ 7 X normal full power power background	A or C
4	Main steamline isolation valve closure (6)	≤ 10% valve closure	A or C
2	Turbine control valve fast closure (9)	≥ 40% turbine/generator load mismatch(10)	A or C
2	Turbine stop valve closure (9)	≤ 10% valve closure	A or C
2	Turbine EHC control fluid low pressure (9)	≥ 900 psig	A or C

TABLE 3.1-4

NOTES FOR TABLES 3.1-1, 3.1-2, AND 3.1-3

1. There shall be two operable trip systems or one operable and one tripped system for each function.

2. If the first column cannot be met for one of the trip systems, that trip system shall be tripped. If the first column cannot be met for both trip systems, the appropriate actions listed below shall be taken:

   A. Initiate insertion of operable rods and complete insertion of all operable rods within 4 hours.

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

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

3. An APRM will be considered inoperable if there are fewer than 2 LPRM inputs per level or there are less than 50% of the normal complement of LPRM's to an APRM.

4. Permissible to bypass, with control rod block for reactor protection system reset in refuel and shutdown positions of the reactor mode switch.

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

6. The design permits closure of any one line without a scram being initiated.

7. Automatically bypassed when reactor pressure is < 1060 psig.

8. The +8-inch trip point is the water level as measured by the instrumentation outside the shroud. The water level inside the shroud will decrease as power is increased to 100% in comparison to the level outside the shroud to a maximum of 7 inches. This is due to the pressure drop across the steam dryer. Therefore, at 100% power, an indication of +8 inch water level will actually be +1 inch inside the shroud. 1 inch on the water level instrumentation is ≥ 504" above vessel zero. (See Bases 3.2).

9. Permissible to bypass when first stage turbine pressure is less than that which corresponds to 45% rated steam flow. (< 400 psi)

10. Trips upon actuation of the fast-closure solenoid which trips the turbine control valves.

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

12. Channel shared by the reactor protection and containment isolation system.

TABLE 4.1-1
SCRAM INSTRUMENTATION AND LOGIC SYSTEMS FUNCTIONAL TESTS

MINIMUM FUNCTIONAL TEST FREQUENCIES FOR SAFETY INSTRUMENTATION, LOGIC SYSTEMS, AND CONTROL CIRCUITS

Instrument Channel	Group(3)	Functional Test(7)	Minimum Frequency(4)
Mode switch in shutdown	A	Place mode switch in shutdown	Each refueling outage
Manual scram	A	Trip channel and alarm	Every 3 months
IRM			
High flux	C	Trip channel and alarm(5)	Before each startup and weekly during refueling (6)
Inoperative	C	Trip channel and alarm	Before each startup and weekly during refueling(6)
APRM			
High flux	B	Trip output relays(5)	Once each week
Inoperative	B	Trip output relays	Once each week
Downscale	B	Trip output relays(5)	Once each week
High flux 15%	C	Trip output relays(5)	Before each startup and weekly during refueling(6)
High reactor pressure	A	Trip channel and alarm	(1)
High drywell pressure	A	Trip channel and alarm	(1)
Reactor low water level(2)	B	(8)	(1)
High water level in scram (9) discharge volume (thermal and dp switches)	A	Trip channel and alarm	Every 3 months
Turbine condenser low vacuum	A	Trip channel and alarm	(1)
Main steamline high radiation(2)	B	Trip channel and alarm(5)	once each week
Main steamline isolation valve closure	A	Trip channel and alarm	(1)
Turbine control valve fast closure	A	Trip channel and alarm	(1)
Turbine stop valve closure	A	Trip channel and alarm	(1)
Turbine EHC control fluid low pressure	A	Trip channel and alarm	(1)

TABLE 4.1-1 (Cont'd)

Notes:

1. Initially once per month until exposure hours (M as defined on Figure 4.1-1) are 2.0 X 10^5; thereafter, according to Figure 4.1-1 with an interval not less than month nor more than 3 months. The compilation of instrument failure rate data may include data obtained from other boiling water reactors for which the same design instrument operates in an environment similar to that of Quad-Cities Units 1 and 2.

2. An instrument check shall be performed on low reactor water level once per day and on high steamline radiation once per shift.

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

4. Functional tests are not required when the systems are not required to be operable or are tripped. If tests are missed, they shall be performed prior to returning the systems to an operable status.

5. This instrumentation is exempted from the instrument functional test definition (1.0 Definition F). This instrument functional test will consist of injecting a simulated electrical signal into the measurement channels.

6. Frequency need not exceed weekly.

7. A functional test of the logic of each channel is performed as indicated. This coupled with placing the mode switch in shutdown each refueling outage constitutes a logic system functional test of the scram system.

8. A functional test of the master and slave trip units is required monthly. A calibration of the trip unit is to be performed concurrent with the functional testing.

9. Only the electronics portion of the thermal switches will be tested using an electronic calibrator during the three month test. A water column or equivalent will be used to test the dp switches.

TABLE 4.1-2

SCRAM INSTRUMENT CALIBRATION

MINIMUM CALIBRATION FREQUENCIES FOR REACTOR PROTECTION INSTRUMENT CHANNELS

Instrument Channel	Group(1)	Calibration Standard(5)	Minimum Frequency(2)
High flux IRM	C	Comparison to APRM after heat balance	Every controlled shutdown(4)
High flux APRM			
Output signal	B	Heat balance	Once every 7 days
Flow bias	B	Standard pressure and voltage source	Refueling outage
LPRM	B(6)	Using TIP system	Every 1000 equivalent full power hours
High reactor pressure	A	Standard pressure source	Every 3 months
High drywell pressure	A	Standard pressure source	Every 3 months
Reactor low water level	B	Water level	[illegible]
Turbine condenser low vacuum	A	Standard vacuum source	Every 3 months
Main steamline high radiation	B	Appropriate radiation source (3)	Refueling outage
Turbine EHC control fluid low pressure	A	Pressure source	Every 3 months
Highwater level in scram discharge volume (dp only)	A	Water level	Refueling outage

Notes:

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

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

3. A current source provides an instrument channel alignment every 3 months.

4. Maximum calibrat[illegible] freque[illegible] need no[illegible] exceed once per week.

5. Response time is not p[illegible] the rou[illegible] trument check and calibration but will be checked every refu[illegible]

6. Does not provide scra[illegible]

7. Trip units are calibrated [illegible]ently with functional testing. Transmitters are calibrated once [illegible]ating cycle.

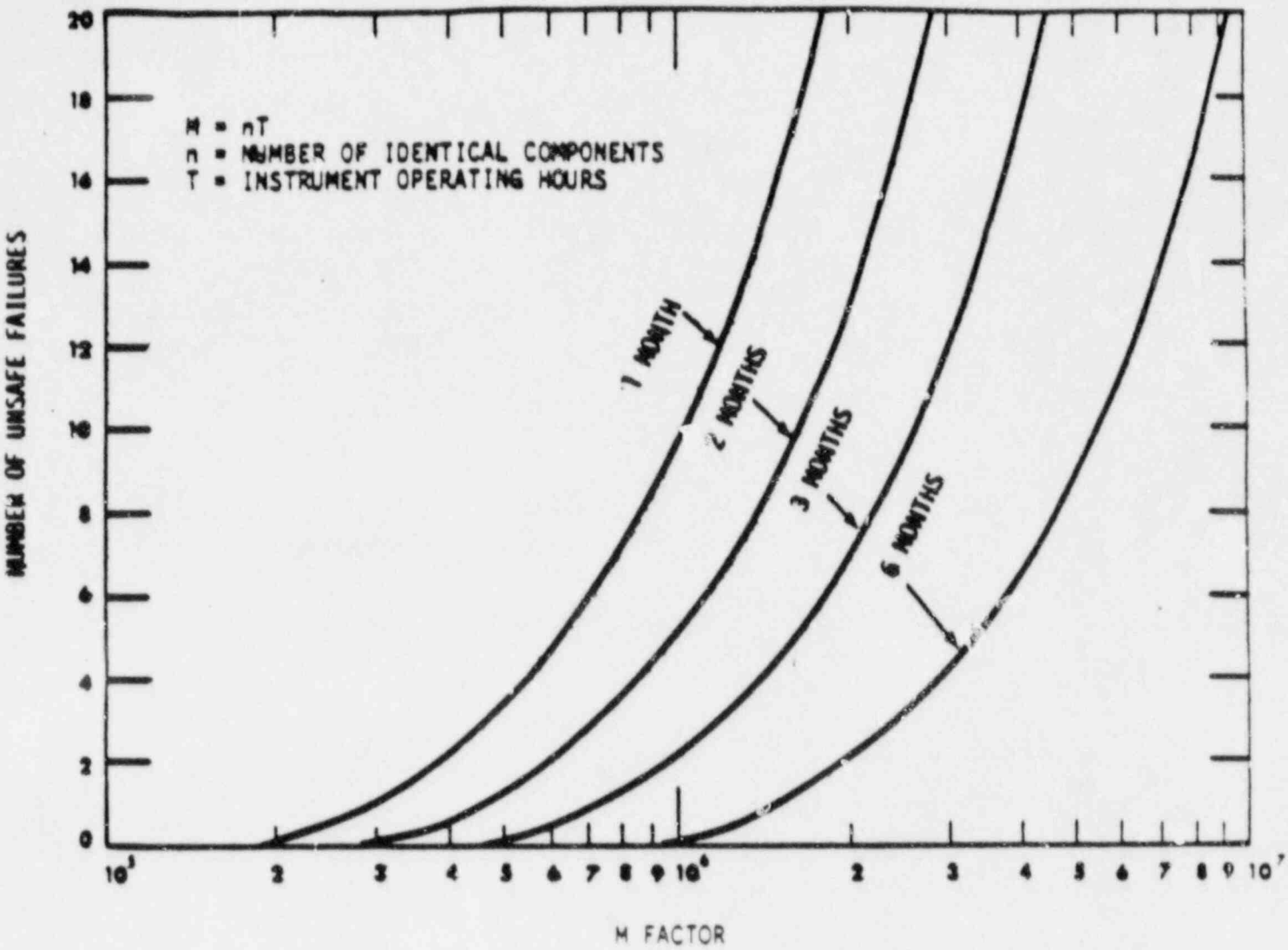


FIGURE 4.1-1

GRAPHICAL AID IN THE SELECTION
OF AN ADEQUATE INTERVAL BETWEEN TESTS

3.2/4.2 PROTECTIVE INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to the plant instrumentation which performs a protective function.

Objective:

To assure the operability of protective instrumentation.

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the surveillance requirements of the instrumentation that performs a protective function.

Objective:

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

SPECIFICATIONS

A. Primary Containment Isolation Functions

When primary containment integrity is required, the limiting conditions of operation for the instrumentation that initiates primary containment isolation are given in Table 3.2-1.

A. Primary Containment Isolation Functions

Instrumentation and logic systems shall be functionally tested and calibrated as indicated in Table 4.2-1.

B. Core and Containment Cooling Systems - Initiation and Control

The limiting conditions for operation for the instrumentation that initiates or controls the core and containment cooling systems are given in Table 3.2-2. This instrumentation must be operable when the system (s) it initiates or controls are required to be operable as specified in Specification 3.5.

B. Core and Containment Cooling Systems - Initiation and Control

Instrumentation and logic systems shall be functionally tested and calibrated as indicated in Table 4.2-1.

C. Control Rod Block Actuation

1. The limiting conditions of operation for the instrumentation that initiates control rod block are given in Table 3.2-3.

C. Control Rod Block Actuation

Instrumentation and Logic systems shall be functionally tested and calibrated as indicated in Table 4.2-1.

2. The minimum number of operable instrument channels specified in Table 3.2-3 for the rod block monitor may be reduced by one in one of the trip systems for maintenance and/or testing, provided that this condition does not last longer than 24 hours in any 30-day period. If this condition exists for more than 24 hours in a 30-day period, the system shall be tripped.

D. Refueling Floor Radiation Monitors

1. Except as specified in Specification 3.2.D.2, the two refueling floor radiation monitors shall be operable whenever irradiated fuel or components are present in the fuel storage pool and during refueling or fuel movement operations.

2. One of the two refueling floor radiation monitors may be inoperable for 24 hours. If the inoperable monitor is not restored to service in this time, the reactor building ventilation system shall be isolated and the standby gas treatment operated until repairs are complete.

3. The trip setting for the refueling floor radiation monitors shall be set at a value of 100 mR/hr.

4. Upon loss of both refueling floor radiation monitors while in use, the reactor building ventilation system shall be isolated and the standby gas treatment operated.

D. Refueling Floor Radiation Monitors

The two refueling floor radiation monitors shall be functionally tested and calibrated as indicated in Table 4.2-1. Reactor building ventilation isolation and standby gas treatment system initiation shall be performed at least each operating cycle.

E. Postaccident Instrumentation

The limiting conditions for operation for the instrumentation which is read out in the control room, required for postaccident monitoring are given in Table 3.2-4.

F. Control Room Ventilation System Isolation

1. The control room ventilation systems are isolated from outside air on a signal of high drywell pressure, low water level, high main steamline flow, high toxic gas concentration, high radiation in either of the reactor building ventilation exhaust ducts, or manually. Limiting conditions for operation shall be as indicated in Table 3.2-1 and Specification 3.2.H. and 3.2.F.2.

2. The toxic gas detection instrumentation shall consist of a chlorine, ammonia, and sulphur dioxide analyzer with each trip setpoint set at:

   a. Chlorine concentration $\leq$ 5 ppm.
   b. Ammonia concentration $\leq$ 50 ppm.
   c. Sulphur dioxide concentration $\leq$ 3 ppm.

   The provisions of Specification 3.0.A. are not applicable

E. Postaccident Instrumentation

Postaccident instrumentation shall be functionally tested and calibrated as indicated in Table 4.2-2.

F. Control Room Ventilation System Isolation

1. Surveillance for instrumentation which initiates isolation of control room ventilation shall be as specified in Table 4.2-1.

2. Manual isolation of the control room ventilation system shall be demonstrated once every refueling outage.

G. Radioactive Liquid Effluent Instrumentation

The effluent monitoring instrumentation shown in Table 3.2-5 shall be operable with alarm setpoints set to ensure that the limits of Specification 3.8.B are not exceeded. The alarm setpoints shall be determined in accordance with the ODCM.

1. With a radioactive liquid effluent monitoring instrument alarm/trip setpoint less conservative than required, without delay suspend the release of radioactive liquid effluents monitored by the affected instrument, or declare the instrument inoperable, or change the setpoint so it is acceptably conservative.

2. With one or more radioactive liquid effluent monitoring instruments inoperable, take the action shown in Table 3.2-5. Exert best efforts to return the instrument to operable status within 30 days and, if unsuccessful, explain in the next Semi-Annual Radioactive Effluent Release Report why the inoperability was not corrected in a timely manner. This is in lieu of an LER.

3. In the event a limiting condition for operation and associated action requirements cannot be satisfied because of circumstances in excess of those addressed in the specifications, provide a 30-day written report to the NRC, and no changes are required in the operational condition of the plant, and this does not prevent the plant from entry into an operational mode.

G. Radioactive Liquid Effluent Instrumentation

Each radioactive liquid effluent monitoring instrument shown in Table 4.2-3 shall be demonstrated operable by performance of the given source check, instrument check, calibration, and functional test operations at the frequencies shown in Table 4.2-3.

H. Radioactive Gaseous Effluent Instrumentation

The effluent monitoring instrumentation shown in Table 3.2-6 shall be operable with alarm/trip setpoints set to ensure that the limits of Specification 3.8.A are not exceeded. The alarm/trip setpoints shall be determined in accordance with the ODCM.

1. With a radioactive gaseous effluent monitoring instrument alarm/trip set point less conservative than required, without delay suspend the release of radioactive gaseous effluents monitored by the affected instrument, or declare the instrument inoperable, or change the setpoint so it is acceptably conservative.

2. With one or more radioactive gaseous effluent monitoring instruments inoperable, take the action shown in Table 3.2-6. Exert best efforts to return the instrument to operable status within 30 days and, if unsuccessful, explain in the next Semi-Annual Radioactive Effluent Release Report why the inoperability was not corrected in a timely manner. This is in lieu of an LER.

3. In the event a limiting condition for operation and associated action requirements cannot be satisfied because of circumstances in excess of those addressed in the specifications, provide a 30-day written report to the NRC and no changes are required in the operational condition of the plant, and this does not prevent the plant from entry into an operational mode.

H. Radioactive Gaseous Effluent Instrumentation

Each radioactive gaseous radiation monitoring instrument in Table 4.2-4 shall be demonstrated operable by performance of the given source check, instrument check, calibration, and functional test operations at the frequency shown in Table 4.2-4.

3.2 LIMITING CONDITIONS FOR OPERATION BASES

In addition to reactor protection instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operator's ability to control, or terminates operator errors before they result in serious consequences. This set of specifications provides the limiting conditions of operation for the primary system isolation function, initiation of the emergency core cooling system, control rod block and standby gas treatment systems. The objectives of the specifications are (1) to assure the effectiveness of the protective instrumentation when required by preserving its capability to tolerate a single failure of any component of such systems even during periods when portions of such systems are out of service for maintenance and (2) to prescribe the trip settings required to assure adequate performance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations. Some of the settings on the instrumentation that initiate or control core and containment cooling have tolerances explicitly stated where the high or low values are both critical and may have a substantial effect on safety. It should be noted that the setpoints of other instrumentation, where only the high or low end of the setting has a direct bearing on safety, are chosen at a level away from the normal operating range to prevent inadvertent actuation of the safety system involved and exposure to abnormal situations.

Isolation valves are installed in those lines that penetrate the primary containment and must be isolated during a loss-of-coolant accident so that the radiation dose limits are not exceeded during an accident condition. Actuation of these valves is initiated by the protective instrumentation which serves the condition for which isolation is required (this instrumentation is shown in Table 3.2.1). Such instrumentation must be available whenever primary containment integrity is required. The objective is to isolate the primary containment so that the guidelines of 10 CFR 100 are not exceeded during an accident.

The instrumentation which initiates primary system isolation is connected in a dual bus arrangement. Thus the discussion given in the basis for Specification 3.1 is applicable here.

The low reactor level instrumentation is set to trip at > 8 inches on the level instrument (top of active fuel is defined to be 360 inches above vessel zero) and after allowing for the full power pressure drop across the steam dryer the low-level trip is at 504 inches above vessel zero, or 144 inches above the top of active fuel. Retrofit 8x8 fuel has an active fuel

length 1.24 inches longer than earlier fuel designs. However, present trip setpoints were used in the LOCA analyses*. This trip initiates closure of Group 2 and 3 primary containment isolation valves but does not trip the recirculation pumps (reference SAR Section 7.7.2). For a trip setting of 504 inches above vessel zero and a 60-second valve closure time, the valves will be closed before perforation of the cladding occurs even for the maximum break: the setting is therefore adequate.

The low low reactor level instrumentation is set to trip when reactor water level is 444 inches above vessel zero (with top of active fuel defined as 360 inches above vessel zero, -59 inches is 84 inches above the top of active fuel). This trip initiates closure of Group 1 primary containment isolation valves (reference SAR Section 7.7.2.2) and also activates the ECC subsystems, starts the emergency diesel generator, and trips the recirculation pumps. This trip setting level was chosen to be high enough to prevent spurious operation but low enough to initiate ECCS operation and primary system isolation so that no melting of the fuel cladding will occur and so that postaccident cooling can be accomplished and the guidelines of 10 CFR 100 will not be exceeded. For the complete circumferential break of a 28-inch recirculation line and with the trip setting given above, ECCS initiation and primary isolation are initiated and in time to meet the above criteria. The instrumentation also covers the full spectrum of breaks and meets the above criteria.

The high-drywell pressure instrumentation is a backup to the water level instrumentation and, in addition to initiating ECCS, it causes isolation of Group 2 isolation valves. For the breaks discussed above, this instrumentation will initiate ECCS operation at about the same time as the low low water level instrumentation; thus the results given above are applicable here also. Group 2 isolation valves include the drywell vent, purge and sump isolation valves. High-drywell pressure activates only these valves because high drywell pressure could occur as the result of non-safety-related causes such as not purging the drywell air during start-up. Total system isolation is not desirable for these conditions, and only the valves in Group 2 are required to close. The low low water level instrumentation initiates protection for the full spectrum of loss-of-coolant accidents and causes a trip of Group 1 primary system isolation valves.

Venturi tubes are provided in the main steamlines as a means of measuring steam flow and also limiting the loss of mass inventory from the vessel during a steamline break accident. In addition to monitoring steam flow, instrumentation is provided which causes a trip of Group 1 isolation valves. The primary function of the instrumentation is to detect a break in the main steamline, thus only Group 1 valves are closed. For the worst-case accident, main steamline break outside the drywell, this trip

* Loss of coolant accident analysis for Dresden Units 2 & 3 and Quad Cities Units 1 & 2, NEDO-24146A, April, 1979

setting of 140% of rated steam flow, in conjunction with the flow limiters and main steamline valve closure, limits the mass inventory loss such that fuel is not uncovered, fuel temperatures remain less than 1500° F, and release of radioactivity to the environs is well below 10 CFR 100 guidelines (reference SAR Sections 14.2.3.9 and 14.2.3.10).

Temperature monitoring instrumentation is provided in the main steamline tunnel to detect leaks in this area. Trips are provided on this instrumentation and when exceeded cause closure of Group 1 isolation valves. Its setting of 200° F is low enough to detect leaks of the order of 5 to 10 gpm; thus it is capable of covering the entire spectrum of breaks. For large breaks, it is a backup to high-steam flow instrumentation discussed above, and for small breaks with the resulting small release of radioactivity, gives isolation before the guidelines of 10 CFR 100 are exceeded.

High radiation monitors in the main steamline tunnel have been provided to detect gross fuel failure. This instrumentation causes closure of Group 1 valves, the only valves required to close for this accident. With the established setting of 7 times normal background and main steamline isolation valve closure, fission product release is limited so that 10 CFR 100 guidelines are not exceeded for this accident (reference SAR Section 12.2.1.7).

Pressure instrumentation is provided which trips when main steamline pressure drops below 825 psig. A trip of this instrumentation results in closure of Group 1 isolation valves. In the Refuel and Startup/Hot Standby modes this trip function is bypassed. This function is provided primarily to provide protection against a pressure regulator malfunction which would cause the control and/or bypass valve to open. With the trip set at 825 psig, inventory loss is limited so that fuel is not uncovered and peak cladding temperatures are much less than 1500° F; thus, there are no fission products available for release other than those in the reactor water (reference SAR Section 11.2.3).

The RCIC and the HPCI high flow and temperature instrumentation are provided to detect a break in their respective piping. Tripping of this instrumentation results in actuation of the RCIC or of HPCI isolation valves. Tripping logic for this function is the same as that for the main steamline isolation valves, thus all sensors are required to be operable or in a tripped condition to meet single-failure criteria. The trip settings of 200°F and 300% of design flow and valve closure time are such that core uncovery is prevented and fission product release is within limits.

The instrumentation which initiates ECCS action is arranged in a one-out-of-two taken twice logic circuit. Unlike the reactor scram circuits, however, there is one trip system associated with each function rather than the two trip systems in the reactor protection system. The single-failure criteria are met by virtue of the fact that redundant core cooling functions are provided, e.g., sprays and automatic blowdown and high-pressure coolant injection. The specification requires that if a trip system becomes inoperable, the system which it activates is declared inoperable. For example, if the trip system for core spray A becomes inoperable, core spray A is declared inoperable and the out-of-service specifications of Specification 3.5 govern. This specification preserves the effectiveness of the system with respect to the single-failure criteria even during periods when maintenance or testing is being performed.

The control rod block functions are provided to prevent excessive control rod withdrawal so that MCPR does not go below the MCPR Fuel Cladding Integrity Safety Limit. The trip logic for this function is one out of n; e.g., any trip on one of the six APRM's, eight IRM's, four SRM's will result in a rod block. The minimum instrument channel requirements assure sufficient instrumentation to assure that the single-failure criteria are met. The minimum instrument channel requirements for the RBM may be reduced by one for a short period of time to allow for maintenance, testing, or calibration. This time period is only ~ 3% of the operating time in a month and does not significantly increase the risk of preventing an inadvertent control rod withdrawal.

The APRM rod block function is flow biased and prevents a significant reduction in MCPR, especially during operation at reduced flow. The APRM provides gross core protection, i.e., limits the gross withdrawal of control rods in the normal withdrawal sequence.

In the refuel and startup/hot standby modes, the APRM rod block function is set at 12% of rated power. This control rod block provides the same type of protection in the Refuel and Startup/Hot Standby modes as the APRM flow-biased rod block does in the Run mode, i.e., prevents control rod withdrawal before a scram is reached.

The RBM rod block function provides local protection of the core, i.e., the prevention of transition boiling in a local region of the core for a single rod withdrawal error from a limiting control rod pattern. The trip point is flow biased. The worst-case single control rod withdrawal error is analyzed for each reload to assure that, with the specific trip settings, rod withdrawal is blocked before the MCPR reaches the fuel cladding integrity safety limit.

Below 30% power, the worst-case withdrawal of a single control rod without rod block action will not violate the fuel cladding integrity safety limit. Thus the RBM rod block function is not required below this power level.

The IRM block function provides local as well as gross core protection. The scaling arrangement is such that the trip setting is less than a factor of 10 above the indicated level. Analysis of the worst-case accident results in rod block action before MCPR approaches the MCPR fuel cladding integrity safety limit.

A downscale indication on an APRM is an indication the instrument has failed or is not sensitive enough. In either case the instrument will not respond to changes in control rod motion, and the control rod motion is thus prevented. The downscale trips are set at 3/125 of full scale.

The SRM rod block with $\leq$ 100 CPS and the detector not full inserted assures that the SRM's are not withdrawn from the core prior to commencing rod withdrawal for startup. The scram discharge volume high water level block provide annunciation for operator action. The alarm setpoint has been selected to provide adequate time to allow determination of the cause of level increase and corrective action prior to automatic scram initiation.

For effective emergency core cooling for small pipe breaks the HPCI system must function since reactor pressure does not decrease rapidly enough to allow either core spray or LPCI to operate in time. The automatic pressure relief function is provided as a backup to the HPCI in the event the HPCI does not operate. The arrangement of the tripping contacts is such as to provide this function when necessary and minimize spurious operation. The trip settings given in the specification are adequate to assure the above criteria are met (reference SAR Section 6.2.6.3). The specification preserves the effectiveness of the system during periods of maintenance, testing or calibration and also minimizes the risk of inadvertent operation, i.e., only one instrument channel out of service.

Two radiation monitors are provided on the refueling floor which initiate isolation of the reactor building and operation of the standby gas treatment systems. The trip logic is one out of two. Trip settings of 100 mR/hr for the monitors on the refueling floor are based upon initiating normal ventilation isolation and standby gas treatment system operation so that none of the activity released during the refueling accident leaves the reactor building via the normal ventilation stack but that all the activity is processed by the standby gas treatment system.

The instrumentation which is provided to monitor the postaccident condition is listed in Table 3.2-4. The instrumentation listed and the limiting conditions for operation on these systems ensure adequate monitoring of the containment following a loss-of-coolant accident. Information from this instrumentation will provide the operator with a detailed knowledge of the conditions resulting from the accident; based on this information he can make logical decisions regarding postaccident recovery.

The specifications allow for postaccident instrumentation to be out of service for a period of 7 days. This period is based on the fact that several diverse instruments are available for guiding the operator should an accident occur, on the low probability of an instrument being out of service and an accident occurring in the 7-day period, and on engineering judgment.

The normal supply of air for the control room ventilation system Trains "A" and "B" is outside the service building. In the event of an accident, this source of air may be required to be shut down to prevent high doses of radiation in the control room. Rather than provide this isolation function on a radiation monitor installed in the intake air duct, signals which indicate an accident, i.e., high drywell pressure, low water level, main steamline high flow, or high radiation in the reactor building ventilation duct, will cause isolation of the intake air to the control room. The above trip signals result in immediate isolation of the control room ventilation system and thus minimize any radiation dose. Manual isolation capability is also provided. Isolation from high toxic chemical concentration has been added as a result of the "Control Room Habitability Study" submitted to the NRC in December 1981 in response to NUREG-0737 Item III D.3.4. As explained in Section 3 of this study, ammonia, chlorine, and sulphur dioxide detection capability has been provided. The setpoints chosen for the control room ventilation isolation are based on early detection in the outside air supply at the odor threshold, so that the toxic chemical will not achieve toxicity limit concentrations in the Control Room.

The radioactive liquid and gaseous effluent instrumentation is provided to monitor the release of radioactive materials in liquid and gaseous effluents during releases. The alarm setpoints for the instruments are provided to ensure that the alarms will occur prior to exceeding the limits of 10 CFR 20.

4.2 SURVEILLANCE REQUIREMENTS BASES

The instrumentation listed in Table 4.2-1 will be functionally tested and calibrated at regularly scheduled intervals. Although this instrumentation is not generally considered to be as important to plant safety as the reactor protection system, the same design reliability goal of 0.99999 is generally applied for all applications of one-out-of-two taken twice logic. Therefore, on-off sensors are tested once every 3 months and bistable trips associated with analog sensors and amplifiers are tested once a week.

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

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

where:

i = the optimum interval between tests,

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

r = the expected failure rate of the relays.

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

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

$$= \sim 40 \text{ days}$$

For additional margin a test interval of once per month will be used initially.

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

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

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

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

The formula given above minimizes the unavailability of a single channel which must be bypassed during testing. The minimization of the unavailability is illustrated by curve 1 of Figure 4.2-1, which assumes that a channel has a failure rate of 0.1×10^{-6}/hour and 0.5 hour is required to test it. The unavailability is a minimum at a test interval i, of 3.6×10^{3} hours.

If two similar channels are used in a one-out-of-two configuration, the test interval for minimum availability changes as a function of the rules for testing. The simplest case is to test each one independent of the other. In this case, there is assumed to be a finite probability that both may be bypassed at one time. This case is shown by curve 2. Note that the unavailability is lower, as expected for a redundant system, and the minimum occurs at the same test interval. Thus, if the two channels are tested independently, the equation above yields the test interval for minimum unavailability.

A more usual case is that the testing is not done independently. If both channels are bypassed and tested at the same time, the result is shown in curve 3. Note that the minimum occurs at about 40,000 hours, much longer than for Cases 1 and 2. Also, the minimum is not nearly as low as Case 2, which indicates that this method of testing does not take full advantage of the redundant channel. Bypassing both channels for simultaneous testing should be avoided.

The most likely case would be to stipulate that one channel be bypassed, tested, and restored, and then immediately following the second channel be bypassed, tested, and restored. This is shown by curve 4. Note that there is not true minimum. The curve does have a definite knee, and very little reduction in system unavailability is achieved by testing at a shorter interval than computed by the equation for a single channel.

The best test procedure of all those examined is to perfectly stagger the tests. This is, if the test interval is 4 months, test one of the other channels every 2 months. This is shown in curve 5. The difference between Cases 4 and 5 is negligible. There may be other arguments, however, that more strongly support the perfectly staggered tests, including reductions in human error.

The conclusions to be drawn are these:

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

b. More than one channel should not be bypassed for testing at any one time.

Reactor water level instruments 1-263-73A & B, HPCI high steam flow instruments 1-2389A-D, and HPCI steam line low pressure instruments 1-2352 & 2353 have been modified to be analog trip systems. The analog trip system consists of an analog sensor (transmitter) and a master/slave trip unit setup which ultimately drives a trip relay. The frequency of calibration and functional testing for instrument loops of the analog trip system has been established in Licensing Topical Report NEDO-21617-A (December 1978). With the one-out-of-two-taken-twice logic, NEDO-21617-A states that each trip unit be subjected to a calibration/functional test frequency of one month. An adequate calibration/surveillance test interval for the transmitter is once per operating cycle.

The radiation monitors in the ventilation duct and on the refueling floor which initiate building isolation and standby gas treatment operation are arranged in two one-out-of two logic systems. The bases given above for the rod blocks apply here also and were used to arrive at the functional testing frequency.

Based on experience at Dresden Unit 1 with instruments of similar design, a testing interval of once every 3 months has been found to be adequate.

The automatic pressure relief instrumentation can be considered to be a one-out-of-two logic system, and the discussion above applies to it also.

The instrumentation which is required for the postaccident condition will be tested and calibrated at regularly scheduled intervals. The basis for the calibration and testing of this instrumentation is the same as was discussed above for the reactor protection system and the emergency core cooling systems.

References

1. B. Epstein and A. Shiff, "Improving Availability and Readiness of Field Equipment Through Periodic Inspection", UCRL-50451, Laurence Radiation Laboratory, p 10, Equation (24), July 16, 1968

TABLE 3.2-1

INSTRUMENTATION THAT INITIATES PRIMARY CONTAINMENT ISOLATION FUNCTIONS

Minimum Number of Operable or Tripped Instrument Channels[1]	Instruments	Trip Level Setting	Action[2]
4	Reactor low water[5]	>144 inches above top of active fuel*	A
4	Reactor low low water	≥84 inches above top of active fuel*	A
4	High drywell pressure[5]	≤2.5 psig [3]	A
16	High flow main steamline[5]	≤140% of rated steam flow	B
16	High temperature main steamline tunnel	≤200° F	B
4	High radiation main steamline tunnel[6]	≤7 x normal rated power background	B
4	Low main steam pressure[4]	≥825 psig	B
4	High flow RCIC steamline	≤300 % of rated steam flow(7)	C
16	RCIC turbine area high temperature	≤200° F	C
4	High flow HPCI steamline	≤300% of rated steam flow(7)	D
16	HPCI area high temperature	≤200° F	D

Notes

1. Whenever primary containment integrity is required, there shall be two operable or tripped systems for each function, except for low pressure main steamline which only need be available in the Run position.

2. Action, if the first column cannot be met for one of the trip systems, that trip system shall be tripped.

   If the first column cannot be met for both trip systems, the appropriate actions listed below shall be taken.

   A. Initiate an orderly shutdown and have the reactor in Cold Shutdown condition in 24 hours.

   B. Initiate an orderly load reduction and have reactor in Hot Standby within 8 hours.

   C. Close isolation valves in RCIC system.

   D. Close isolation valves in HPCI subsystem.

3. Need not be operable when primary containment integrity is not required.

4. The isolation trip signal is bypassed when the mode switch is in Refuel or Startup/ Hot Standby.

5. The instrumentation also isolates the control room ventilation system.

6. This signal also automatically closes the mechanical vacuum pump discharge line isolation valves.

7. Includes a time delay of $3 \leq t \leq 10$ seconds.

* Top of active fuel is defined as 360" above vessel zero for all water levels used in the LOCA analysis (see Bases 3.2).

TABLE 3.2-2

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum Number of Operable or Tripped Instrument Channels[1]	Trip Function	Trip Level Setting	Remarks
4	Reactor low low water level	≥84 inches (+ 4 inches/-0 inch) above top of active fuel*	1. In conjunction with low reactor pressure initiates core spray and LPCI. 2. In conjunction with high-drywell pressure 120-second time delay and low-pressure core cooling interlock initiates auto blowdown. 3. Initiates HPCI and RCIC. 4. Initiates starting of diesel generators.
4[4]	High-drywell pressure[2],[3]	≤2.5 psig	1. Initiates core spray, LPCI, HPCI, and SBGTS. 2. In conjunction with low low water level, 120-second time delay, and low-pressure core cooling interlock initiates auto blowdown. 3. Initiates starting of diesel generators. 4. Initiates isolation of control room ventilation.
2	Reactor low pressure	300 psig≤p≤350 psig	1. Permissive for opening core spray and LPCI admission valves. 2. In conjunction with low low reactor water level initiates core spray and LPCI.
	Containment spray interlock		Prevents inadvertent operation of containment spray during accident conditions.
2[3] 4[3]	2/3 core height containment high pressure	≥2/3 core height 0.5 psig≤p≤1.5 psig	
2	Timer auto blowdown	≤120 seconds	In conjunction with low low reactor water level, high-drywell pressure, and low-pressure core cooling interlock initiates auto blow-down.

* Top of active fuel is defined at 360" above vessel zero for all water levels used in the LOCA analysis

TABLE 3.2-2 (Cont'd)

Minimum Number of Operable or Tripped Instrument Channels[1]	Trip Function	Trip Level Setting	Remarks
4	Low-pressure core cooling pump discharge pressure	100 psig≤p≤150 psig	Defers APR actuation pending confirmation of low-pressure core cooling system operation.
2/BUS [5]	Undervoltage on emergency buses	3045 ± 5% volts	1. Initiates starting of diesel generators. 2. Permissive for starting ECCS pumps. 3. Removes nonessential loads from buses. 4. Bypasses degraded voltage timer.
2[5]/BUS	Degraded Voltage on 4 KV Emergency Buses	3840 volts ± 2% with 5 ± 5% minute time delay and 7 ± 20% second inherent time delay	Initiates alarm and picks up time delay relay. Diesel Generator picks up load if degraded voltage not corrected after time delay.

NOTES

1. For all positions of the reactor mode selector switch (except for the containment interlock) whenever any ECCS subsystem is required to be operable, there shall be two operable trip systems. If the first column cannot be met for one or both of the trip systems, the systems actuated shall be declared inoperable and Specifications 3.5 or 3.9 shall govern.

2. Need not be operable when primary containment integrity is not required.

3. If an instrument is inoperable, it shall be placed (or simulated) in the tripped condition so that it will not prevent containment spray.

4. There are a total of eight high drywell pressure sensors. Four are used for core spray and LPCI initiation, and four are used for HPCI and auto blowdown initiation. This specification applies to each set of four sensors.

5. With the number of operable channels one less than the total number of channels, operation may proceed until performance of the next required functional test, provided the inoperable channel is placed in the tripped condition within one hour.

TABLE 3.2-3

INSTRUMENTATION THAT INITIATES ROD BLOCK

Minimum Number of Operable or Tripped Instrument Channels per Trip System (1)	Instrument	Trip Level Setting
2	APRM upscale (flow bias)[7]	$\leq[0.58W_D + 50]\ \frac{FRP}{MFLPD}$ [2]
2	APRM upscale (Refuel and Startup/Hot Standby mode)	$\leq$12/125 full scale
2	APRM downscale[7]	$\geq$3/125 full scale
1	Rod block monitor upscale (flow bias)[7]	$\leq 0.65W_D + 43$[2]
1	Rod block monitor downscale[7]	$\geq$3/125 full scale
3	IRM downscale[3] [8]	$\geq$3/125 full scale
3	IRM upscale[8]	$\leq$108/125 full scale
2[5]	SRM detector not in Startup position [4]	$\geq$2 feet below core centerline
3	IRM detector not in Startup position [8]	$\geq$2 feet below core centerline
2[5] [6]	SRM upscale	$\leq 10^5$ counts/sec
2[5]	SRM downscale [9]	$\geq 10^2$ counts/sec
1 (per bank)	High water level in scram discharge volume (SDV)	$\leq$ 25 gallons (per bank)
1	SDV high water level scram trip bypassed	NA

TABLE 3.2-3 (Con't)

Notes

1. For the Startup/Hot Standby and Run positions of the reactor mode selector switch, there shall be two operable or tripped trip systems for each function except the SRM rod blocks. IRM upscale and IRM downscale need not be operable in the Run position, APRM downscale, APRM upscale (flow biased), and RBM downscale need not be operable in the Startup/Hot Standby mode. The RBM upscale need not be operable at less than 30% rated thermal power. One channel may be bypassed above 30% rated thermal power provided that a limiting control rod pattern does not exist. For systems with more than one channel per trip system, if the first column cannot be met for one of the two trip systems, this condition may exist for up to 7 days provided that during that time the operable system is functionally tested immediately and daily thereafter; if this condition lasts longer than 7 days the system shall be tripped. If the first column cannot be met for both trip systems, the systems shall be tripped.

2. W_D is the percent of drive flow required to produce a rated core flow of 98 million lb/hr. Trip level setting is in percent of rated power (2511 MWt).

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

4. This function is bypassed when the count rate is $\geq$ 100CPS.

5. One of the four SRM inputs may be bypassed.

6. This SRM function may be bypassed in the higher IRM ranges (ranges 8, 9, and 10) when the IRM upscale rod block is operable.

7. Not required to be operable while performing low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5MWt.

8. This IRM function occurs when the reactor mode switch is in the Refuel or Startup/Hot Standby position.

9. This trip is bypassed when the SRM is fully inserted.

TABLE 3.2-4

POSTACCIDENT MONITORING INSTRUMENTATION REQUIREMENTS[2]

Minimum Number of Operable Channels[1] [3]	Parameter	Instrument Readout Location Unit 1	Number Provided	Range
1	Reactor pressure	901-5	1 2	0-1500 psig 0-1200 psig
1	Reactor water level	901-3	2	-243 inches+57 inches
1	Torus water temperature	901-21	2	0-200° F
1	Torus air temperature	901-21	2	0-600° F
	Torus water level indicator	901-3	1	-5 inches +5 inches (narrow range)
2[6]	Torus water level indicator	901-3	2	0-30 feet (wide range)
	Torus water level sight glass		1	18 inch range (narrow range)
1	Torus pressure	901-3	1	-5 inches Hg to 5 psig
2	Drywell pressure	901-3	1	-5 inches Hg to 5 psig -10 inches Hg to 70 psig
			2	0 to 250 psig
2	Drywell temperature	901-21	6	0-600° F
2	Neutron monitoring	901-5	4	0.1-10^8 CPS
2[4]	Torus to drywell differential pressure		2	0-3 psid
1[8]	Drywell Hydrogen concentration	901-55, 56	2	0-4%
2[7]	Drywell radiation monitor	901-55, 56	2	1 to 10^8 R/h

TABLE 3.2-4 (Cont'd)

Minimum Number of Operable Channels[1] [3]	Parameter	Instrument Readout Location Unit 1	Number Provided	Range
2/valve[5]	Main Steam RV position, acoustic monitor	901-21	1 per valve	NA
	Main Steam RV position, temperature monitor	901-21	1 per valve	0-600°F
2/valve[5]	Main Steam SV position, acoustic monitor	901-21	1 per valve	NA
	Main Steam SV position, temperature monitor	901-21	1 per valve	0-600°F

Notes

1. Instrument channels required during power operation to monitor postaccident conditions.

2. Provisions are made for local sampling and monitoring of drywell atmosphere.

3. In the event any of the instrumentation becomes inoperable for more than 7 days during reactor operation, initiate an orderly shutdown and be in the cold shutdown condition within 24 hours. See notes 4, 5, 6, 7, and 8 for exceptions to this requirement.

4. From and after the date that one of these parameters is reduced to one indication, continued operation is not permissible beyond thirty days unless such instrumentation is sooner made operable. In the event that all indication of these parameters is disabled and such indication cannot be restored in six (6) hours, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition in twenty-four (24) hours.

5. If the number of position indicators is reduced to one indication on one or more valves, continued operation is permissible; however, if the reactor is in a cold shutdown condition for longer than 72 hours, it may not be started up until all position indication is restored. In the event that all position indication is lost on one or more valves and such indication cannot be restored in 30 days, an orderly shutdown shall be initiated, and the reactor shall be depressurized to less than 90 psig in 24 hours.

TABLE 3.2-4 (Cont'd)

6. From and after the date that this parameter is reduced to either one narrow-range indication or one wide-range indication, continued reactor operation is not permissible beyond 30 days unless such instrument is sooner made operable. In the event that either all narrow-range indication or all wide-range indication is disabled, continued reactor operation is not permissible beyond 7 days unless such instruments are sooner made operable. In the event that all indication for this parameter is disabled, and such indication cannot be restored in 6 hours, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition in 24 hours.

7. With less than the minimum number of operable channels, initiate the pre-planned alternate method of monitoring this parameter within 72 hours, and:

   a. either restore the inoperable channel(s) to operable status within 7 days of the event, or

   b. prepare and submit a special report to the NRC within 30 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.

8. From and after the date that one of the drywell hydrogen monitors becomes inoperable, continued reactor operation is permissible.

   a. If both drywell hydrogen monitors are inoperable, continued reactor operation is permissible for up to 30 days provided that during this time the HRSS hydrogen monitoring capability for the drywell is operable.

   b. If all drywell hydrogen monitoring capability is lost, continued reactor operation is permissible for up to 7 days.

TABLE 3.2-5

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

Minimum No. of Operable Channels	Total No. of Channels	Parameter	Action [1]
1	1	Service Water Effluent Gross Activity Monitor	A
1	1	Liquid Radwaste Effluent Flow Rate Monitor	C
1	1	Liquid Radwaste Effluent Gross Activity Monitor	B

Notes

Action A: With less than the minimum number of operable channels, releases via this pathway may continue, provided that at least once per 12 hours grab samples are collected and analyzed for beta or gamma activity at an LLD of less than or equal to 10^{-7} uCi/ml.

Action B: With less than the minimum number of operable channels, effluent releases via this pathway may continue, provided that prior to initiating a release, at least 2 independent samples are analyzed in accordance with Specification 4.8.B.1, and at least 2 members of the facility staff independently verify the release calculation and discharge valving. Otherwise, suspend release of radioactive effluents via this pathway.

Action C: With less than the minimum number of operable channels, releases via this pathway may continue, provided the flow rate is estimated at least once per 4 hours during actual releases. Pump curves may be utilized to estimate flow.

TABLE 3.2-6

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

Minimum No. of Operable Channels [1]	Total No. of Channels	Parameter	Action [2]
1	2	SJAE Radiation Monitors	D
1	2	Main Chimney Noble Gas Activity Monitor	A
1	1	Main Chimney Iodine Sampler	C
1	1	Main Chimney Particulate Sampler	C
1	1	Reactor Bldg. Vent Sampler Flow Rate Monitor	B
1	1	Reactor Bldg. Vent Iodine Sampler	C
1	1	Reactor Bldg. Vent Particulate Sampler	C
1	1	Main Chimney Sampler Flow Rate Monitor	B
1	1	Main Chimney Flow Rate Monitor	B
1	2	Reactor Bldg. Vent Noble Gas Monitor	E
1	1	Main Chimney High Range Noble Gas Monitor	F

Notes

(1) For SJAE monitors, applicable during SJAE operation. For other instrumentation, applicable at all times.

(2) Action A: With the number of operable channels less than the minimum requirement, effluent releases via this pathway may continue, provided grab samples are taken at least once per 8 hour shift and these samples are analyzed within 24 hours.

TABLE 3.2-6 (Con't)

Action B: With the number of operable channels less than the minimum required, effluent releases via this pathway may continue provided that the flow rate is estimated at least once per 4 hours.

Action C: With less than the minimum channels operable, effluent releases via this pathway may continue provided samples are continuously collected with auxiliary sampling equipment, as required in Table 4.8-1.

Action D: With less than the minimum channels operable, gases from the main condenser off gas system may be released to the environment for up to 72 hours provided at least one chimney monitor is operable; otherwise, be in hot stand-by in 12 hours.

Action E: With less than the minimum channels operable, immediately suspend release of radioactive effluents via this pathway.

Action F: With less than the minimum channels operable, initiate the preplanned alternate method of monitoring the appropriate parameter(s) within 72 hours, and:

(1) either restore the inoperable channel(s) to operable status within 7 days of the event, or

(2) prepare and submit a Special Report to the Commission within 30 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.

TABLE 4.2-1

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CORE AND CONTAINMENT COOLING SYSTEMS INSTRUMENTATION, ROD BLOCKS, AND ISOLATIONS(7)

Instrument Channel	Instrument Functional Test (2)	Calibration(2)	Instrument Check(2)
ECCS Instrumentation			
1. Reactor low-low water level	(1)	Once/3 months	Once/day
2. Drywell high pressure	(1)	Once/3 months	None
3. Reactor low pressure	(1)	Once/3 months	None
4. Containment spray interlock			
a. 2/3 core height	(1) (10)	(10)	None
b. Containment pressure	(1)	Once/3 months	None
5. Low pressure core cooling pump discharge	(1)	Once/3 months	None
6. Undervoltage 4-kV essential	Refueling outage	Refueling outage	None
7. Degraded voltage 4-kv essential buses	Refueling outage (8)	Refueling outage	Once/month
Rod Blocks			
1. APRM downscale	(1) (3)	Once/3 months	None
2. APRM flow variable	(1) (3)	Refueling outage	None
3. IRM upscale	(5) (3)	(5) (3)	None
4. IRM downscale	(5) (3)	(5) (3)	None
5. RBM upscale	(1) (3)	Refueling outage	None
6. RBM downscale	(1) (3)	Once/3 months	None
7. SRM upscale	(5) (3)	(5) (3)	None
8. SRM detector not in startup position	(5) (3)	(6)	None
9. IRM detector not in startup position	(5)	(6)	None
10. SRM downscale	(5) (3)	(5) (3)	None
11. High water level in scram discharge volume (SDV)	Once/3 months	Not applicable	None
12. SDV high level trip bypassed	Refueling outage	Not applicable	None
Main Steamline Isolation			
1. Steam tunnel high temperature	Refueling outage	Refueling outage	None
2. Steamline high flow	(1)	Once/3 months	Once/day
3. Steamline low pressure	(1)	Once/3 months	None
4. Steamline high radiation	(1) (4)	Refueling outage	Once/day
5. Reactor low low water level	(1) (10)	(10)	Once/day

TABLE 4.2-1 (Cont'd)

Instrument Channel	Instrument Functional Test (2)	Calibration(2)	Instrument Check(2)
RCIC Isolation			
1. Steamline high flow	Once/3 months(9)	Once/3 months(9)	None
2. Turbine area high temperature	Refueling outage	Refueling outage	None
3. Low reactor pressure	Once/3 months	Once/3 months	None
HPCI Isolation			
1. Steamline high flow	(1) (9)	Once/3 months	None
2. Steamline area high temperature	Refueling outage	Refueling outage	None
3. Low reactor pressure	(1)	Once/3 months	None
Reactor Building Ventilation System Isolation and Standby Treatment System Initiation			
1. Refueling floor radiation monitors	(1)	Once/3 months	Once/day
Steam Jet Air Ejector Off-Gas Isolation			
1. Off-gas radiation monitors	(1) (4)	Refueling outage	Once/day
Control Room Ventilation System Isolation			
1. Reactor low water level	(1)	Once/3 months	Once/day
2. Drywell high pressure	(1)	Once/3 months	None
3. Main steamline high flow	(1)	Once/3 months	Once/day
4. Toxic gas analyzers (chlorine, ammonia, sulphur dioxide)	Once/month	Once/18 months	Once/day

Notes

1. Initially once per month until exposure hours (M as defined on Figure 4.1-1) are 2.0×10^5; thereafter, according to Figure 4.1-1 with an interval not less than 1 month nor more than 3 months. The compilation of instrument failure rate data may include data obtained from other boiling water reactors for which the same design instrument operates in an environment similar to that of Quad Cities Units 1 and 2.

2. Functional tests, calibrations, and instrument checks are not required when these instruments are not required to be operable or tripped.

TABLE 4.2-1 (Cont'd)

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

4. This instrument channel is excepted from the functional test definitions and shall be calibrated using simulated electrical signals once every 3 months.

5. Functional tests shall be performed before each startup with a required frequency not to exceed once per week. Calibrations shall be performed during each startup or during controlled shutdowns with a required frequency not to exceed once per week.

6. The positioning mechanism shall be calibrated every refueling outage.

7. Logic system functional tests are performed as specified in the applicable section for these systems.

8. Functional tests shall include verification of operation of the degraded voltage 5 minute timer and 7 second inherent timer.

9. Verification of the time delay setting of $3 \leq \tau \leq 10$ seconds shall be performed during each refueling outage.

TABLE 4.2-2

POSTACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Minimum Number of Operable Channels*	Parameter	Instrument Readout Location Unit 1	Calibration	Instrument Check
1	Reactor pressure	901-5	Once every 3 months	Once per day
1	Reactor water level	901-3	Once every 3 months	Once per day
1	Torus water temperature	901-21	Once every 3 months	Once per day
1	Torus air temperature	901-21	Once every 3 months	Once per day
	Torus water level indicator (narrow range)	901-3	Once every 3 months	Once per day
2	Torus water level indicator (wide range)	901-3	Once every 18 months	Once per 31 days
	Torus water level sight glass		N/A	None
1	Torus pressure	901-3	Once every 3 months	Once per day
2	Drywell pressure	901-3	Once every 3 months	Once per day
2	Drywell temperature	901-21	Once every 3 months	Once per day
2	Neutron monitoring	901-5	Once every 3 months	Once per day
2	Torus to drywell differential pressure		Once every 6 months	None
1	Drywell Hydrogen concentration	901-55, 56	Once every 3 months	Once per 31 days
2	Drywell radiation monitor	901-55, 56	Once every 18 months ***	Once per 31 days
2/valve	Main Steam RV position, acoustic monitor	901-21	**	Once per 31 days
	Main Steam RV position, temperature monitor	901-21	Once every 18 months	Once per 31 days

TABLE 4.2-2 (con'd)

Minimum Number of Operable Channels*	Parameter	Instrument Readout Location Unit 1	Calibration	Instrument Check
2/valve	Main Steam SV Position, acoustic monitor	901-21	**	Once per 31 days
	Main Steam SV Position, temperature monitor	901-21	Once every 18 months	Once per 31 days

* Instrument channels required during power operation to monitor postaccident conditions.

** Functional tests will be conducted before startup at the end of each refueling outage or after maintenance is performed on a particular safety or relief valve.

*** Calibration shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr; and a one-point calibration check of the detector below 10 R/hr with an installed or portable gamma source.

TABLE 4.2-3

RADIOACTIVE LIQUID EFFLUENT MONITORING
INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Instrument	Instrument Check (1)	Calibration (1)(3)	Functional Test (1)(2)	Source Check (1)
Liquid Radwaste Effluent Gross Activity Monitor	D	R	Q (7)	(6)
Service Water Effluent Gross Activity Monitor	D	R	Q (7)	R
Liquid Radwaste Effluent Flow Rate Monitor	(4)	R	NA	NA

Notes

(1) D = once per 24 hours
M = once per 31 days
Q = once per 92 days
R = once per 18 months
S = once per 6 months

(2) The Instrument Functional Test shall also demonstrate that control room alarm annunciation occurs, if any of the following conditions exist, where applicable.

a. Instrument indicates levels above the alarm setpoint.
b. Circuit failure.
c. Instrument indicates a downscale failure.
d. Instrument controls not set in OPERATE mode.

(3) Calibration shall include performance of a functional test.

(4) Instrument Check to verify flow during periods of release.

(5) Calibration shall include performance of a source check.

(6) Source check shall consist of observing instrument response during a discharge.

(7) Functional test may be performed by using trip check and test circuitry associated with the monitor chassis.

TABLE 4.2-4

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Instrument	Mode(2)	Instrument Check(1)	Calibration(1)(4)	Functional Test(1) (3)	Source Check (1)
Main Chimney Noble Gas Activity Monitor	B	D	R	Q	M
Main Chimney Sampler Flow Rate Monitor	B	D	R	Q(6)	NA
Reactor Bldg. Vent Sampler Flow Rate Monitor	B	D	R	Q(6)	NA
Main Chimney Flow Rate Monitor	B	D	R	Q	NA
Reactor Bldg Vent Activity Monitor	B	D	R	Q	Q
SJAE Activity Monitor	A	D	R	Q	R
Main Chimney Iodine and Particulate Sampler	B	D(5)	NA	NA	NA
Reactor Bldg. Vent Iodine and Particulate Sampler	B	D(5)	NA	NA	NA
Main Chimney High Range Noble Gas Monitor	B	D(5)	R	Q	M

Notes

(1) D = once per 24 hours
M = once per 31 days
Q = once per 92 days
R = once per 18 months

(2) A = during SJAE operation
B = at all times

(3) The Instrument Functional Test shall also demonstrate that control room alarm annunciation occurs, if any of the following conditions exist, where applicable:

a. Instrument indicates levels above the alarm setpoint
b. Circuit failure
c. Instrument indicates a downscale failure
d. Instrument controls not set in OPERATE mode

TABLE 4.2-4 (cont'd)

(4) Calibration shall include performance of a functional test

(5) Instrument check to verify operability of the instrument; that the instrument is in-place and functioning properly.

(6) Functional test shall be performed on local switches providing low flow alarm.

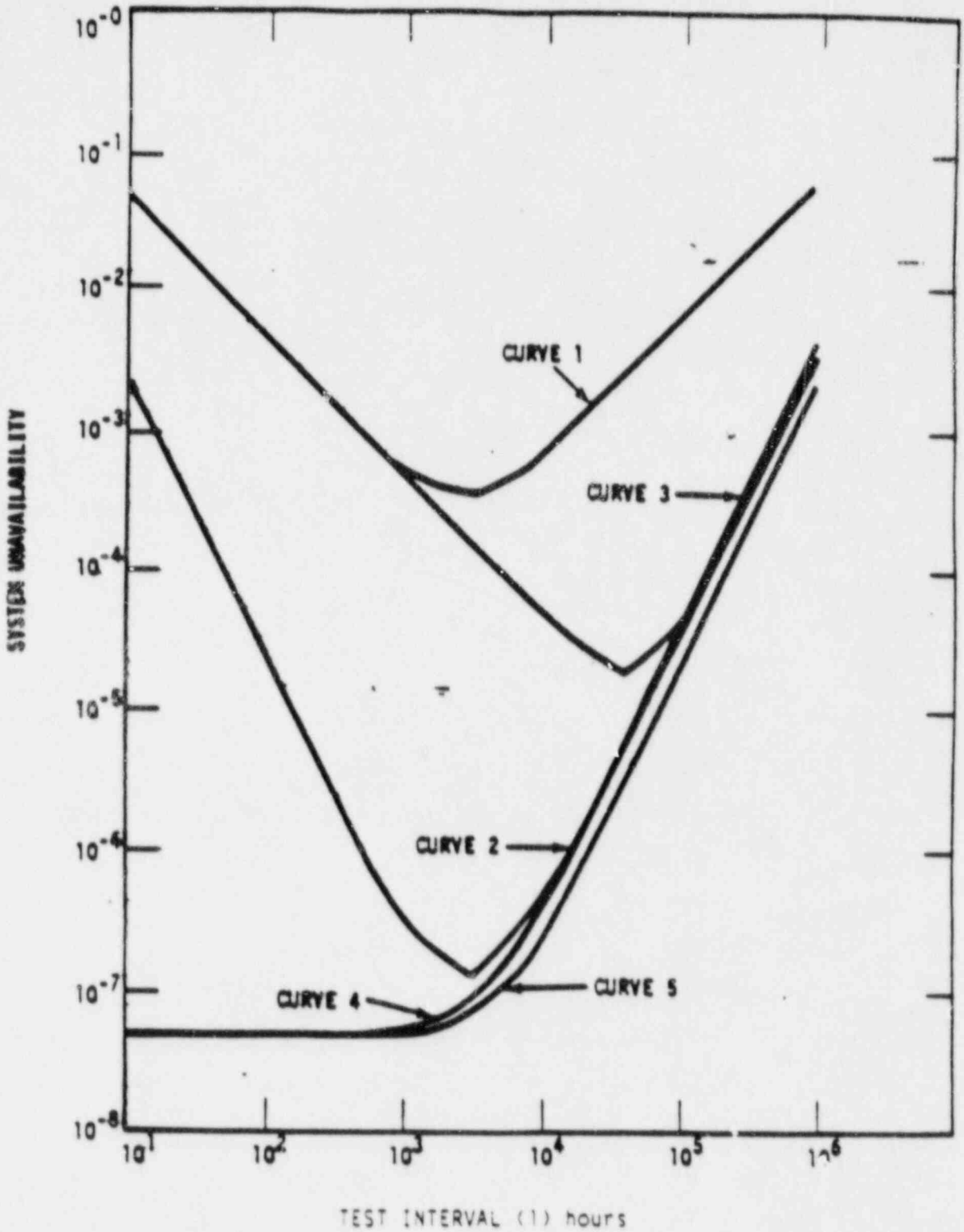


FIGURE 4.2-1

TEST INTERVAL VS. SYSTEM UNAVAILABILITY

3.3/4.3 REACTIVITY CONTROL

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to the operational status of the control rod system.

Objective.

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

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the surveillance requirements of the control rod system.

Objective:

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

SPECIFICATIONS

A. Reactivity Limitations

1. Reactivity margin - core loading

   The core loading shall be limited to that which can be made subcritical in the most reactive condition during the operating cycle with the strongest operable control rod in its full-out position and all other operable rods fully inserted.

2. Reactivity margin - inoperable control rods

   a. Control rod drives which cannot be moved with control rod drive pressure shall be considered inoperable except as in c below. 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

A. Reactivity Limitations

1. Reactivity margin - core loading

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

2. Reactivity margin - inoperable control rods

   Each partially or fully withdrawn operable control rod shall be exercised one notch at least once each week. This test shall be performed at least once per 24 hours in the event power operation is continuing with three or more inoperable control rods or in the event power operation is continuing with one fully or

48 hours unless investigation demonstrates that the cause of the failure is not due to a failed control rod drive mechanism collet housing.

partially withdrawn rod which cannot be moved and for which control rod drive mechanism damage has not been ruled out. The surveillance need not oe completed within 24 hours if the number of inoperable rods has been reduced to less than three and if it has been demonstrated that control rod drive mechanism collet housing failure is not the cause of an immovable control rod.

b. The control rod directional control valves for inoperable controls rods shall be disarmed electrically and the control rods shall be in such positions that Specification 3.3.A.1 is met except as in d below.

c. Control rod drives which are fully inserted and electrically disarmed shall not be considered inoperable.

d. Control rods with scram times greater than those permitted by Specification 3.3.C are inoperable, but if they can be moved with control rod drive pressure they need not be disarmed electrically if Specification 3.3.A.1 is met for each position of these rods.

e. During reactor power operation, the number of inoperable control rods shall not exceed eight.

3. Rod Position Indication System

a. The position of a control rod shall be determined from the rod position indication system (RPIS).

b. If the position of a control rod cannot be determined from the RPIS, such control rod shall be moved to a known position or fully inserted, scrammed, and considered inoperable.

B. Control Rods

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

3. Rod Position Indication System

a. Once per shift during power operation and during control rod withdrawal the control rod display shall be observed for control rod position indication.

b. All control rods that have been fully inserted and scrammed shall be given an insert signal once per shift.

B. Control Rods

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

a. When the rod is withdrawn the first time subsequent to each refueling outage or after maintenance, observe discernible response of the nuclear instrumentation; however, for initial rods when response is not discernible, subsequent exercising of these rods after the reactor is critical shall be performed to verify instrumentation response.

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

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

3. The control rod drive housing support system shall be in place during reactor 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 3.3.A.1 is met.

   a. Control rod withdrawal sequences shall be established so that maximum reactivity that could be added by dropout of any increment of any one control blade would be such that the rod drop accident design limit of 280 cal/gm is not exceeded.

   b. Whenever the reactor is in the Startup/Hot Standby or Run mode below 20% rated thermal power, the rod worth minimizer shall be operable. A second operator or qualified technical person may be used as a substitute for an inoperable rod worth minimizer which fails after withdrawal of at least 12 control rods to the fully withdrawn position. The rod worth minimizer may also be bypassed for low power physics testing to demonstrate the shutdown margin requirements of Specification 3.3.A if a nuclear engineer is present and verifies the step-by-step rod movements of the test procedure.

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

3. The correctness of the control rod withdrawal sequence input to the RWM computer shall be verified after loading the sequence.

   Prior to the start of control rod withdrawal towards criticality, the capability of the rod worth minimizer to properly fulfill its function shall be verified by the following checks:

   a. The RWM computer online diagnostic test shall be successfully performed.

   b. Proper annunciation of the selection error of one out-of-sequence control rod shall be verified.

c. The rod block function of the RWM shall be verified by withdrawing the first rod as an out-of-sequence control rod no more than to the block point.

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

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

5. During operation with limiting control rod patterns, as determined by the nuclear engineer, either:

   a. both RBM channels shall be operable.

   b. control rod withdrawal shall be blocked; or

   c. the operating power level shall be limited so that the MCPR will remain above the MCPR fuel cladding integrity safety limit assuming a single error that results in complete withdrawal of any single operable control rod.

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

6. The scram discharge volume vent and drain valves shall be verified open at least once per 31 days. These valves may be closed intermittently for testing under administrative control and at least once per 92 days, each valve shall be cycled through at least one complete cycle of full travel. At least once each Refueling Outage, the scram discharge volume vent and drain valves will be demonstrated to:

a. Close within 30 seconds after receipt of a signal for control rods to scram, and

b. Open when the scram signal is reset.

C. Scram Insertion Times

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

% Inserted From Fully Withdrawn	Average Scram Insertion Times (sec)
5	0.375
20	0.900
50	2.00
90	3.50

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:

% Inserted From Fully Withdrawn	Average Scram Times (sec)
5	0.398
20	0.954
50	2.12
90	3.80

2. The maximum scram insertion time for 90% of any operable control rods shall not exceed 7 seconds.

C. Scram Insertion Times

1. After refueling outage and prior to operation above 30% power, with reactor pressure above 800 psig, all control rods shall be subject to scram-time measurements from the fully withdrawn position. The scram times for single rod scram testing shall be measured without reliance on the control rod drive pumps.

2. All control rod drives shall have experienced scram test measurements each year. Also, 50% of the control rod drives in each quadrant of the reactor core shall be measured for the scram times specified in Specification 3.3.C during the

interval not more frequently than 16 weeks nor less frequently than 32 weeks. These tests shall be performed with a reactor pressure above 800 psig and may be measured during a reactor scram. Whenever all of the control rod drive scram times have been measured, an evaluation shall be made to provide reasonable assurance that proper control rod drive performance is being maintained. The results of measurements performed on the control rod drives shall be submitted in the annual operating report to the NRC.

3. If Specification 3.3.C.1 cannot be met, the reactor shall not be made supercritical; if operating, the reactor shall be shut down immediately upon determination that average scram time is deficient.

4. If Specification 3.3.C.2 cannot be met, the deficient control rod shall be considered inoperable, fully inserted into the core, and electrically disarmed.

5. If the overall average of the 20% insertion scram time data generated to date in the current cycle exceeds 0.71 seconds, the MCPR operating limit must be modified as required by Specification 3.5.K.

3. The cycle cumulative mean scram time for 20% insertion will be determined immediately following the testing required in Specifications 4.3.C.1 and 4.3.C.2 and the MCPR operating limit adjusted, if necessary, as required by Specification 3.5.K.

D. Control Rod Accumulators

At all reactor operating pressures, a rod accumulator may be inoperable provided that no other control rod in the nine-rod square array around that rod has:

1. an inoperable accumulator,

D. Control Rod Accumulators

Once a shift, check the status of the pressure and level alarms for each accumulator.

2. a directional control valve electrically disarmed while in a nonfully inserted position, or

3. a scram insertion greater than maximum permissible insertion time.

If a control rod with an inoperable accumulator is inserted full-in and its directional control valves are electrically disarmed, it shall not be considered to have an inoperable accumulator, and the rod block associated with that inoperable accumulator may be bypassed.

E. Reactivity Anomalies

The reactivity equivalent of the difference between the actual critical rod configuration and the expected configuration during power operation shall not exceed 1% Δk. If this limit is exceeded, the reactor shall be shutdown until the cause has been determined and corrective actions have been taken. In accordance with Specification 6.6, the NRC shall be notified of this reportable occurrence within 24 hours.

E. Reactivity Anomalies

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

F. Economic Generation Control System

Operation of the unit with the economic generation control system with automatic flow control shall be permissible only in the range of 65% to 100% of rated core flow, with reactor power above 20%.

F. Economic Generation Control System

Prior to entering EGC and once per shift while operating in EGC, the EGC operating parameters will be reviewed for acceptability.

G. If Specifications 3.3.A through D above are not met, an orderly shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

3.3 LIMITING CONDITIONS FOR OPERATION BASES

A. Reactivity Limitations

1. Reactivity margin - core loading

The core reactivity limitation is a restriction to be applied principally to the design of new fuel which may be loaded in the core or into a particular refueling pattern. Satisfaction of the limitation can only be demonstrated at the time of loading and must be such that it will apply to the entire subsequent fuel cycle. The generalized form is that the reactivity of the core loading will be limited so the core can be made subcritical by at least R + 0.25% Δk in the most reactive condition during the operating cycle, with the strongest control rod fully withdrawn and all others fully inserted. The value of R in % Δk is the amount by which the core reactivity, at any time in the operating cycle, is calculated to be greater than at the time of the check; i.e., the initial loading. R must be a positive quantity or zero. A core which contains temporary control or other burnable neutron absorbers may have a reactivity characteristic which increases with core lifetime, goes through a maximum, and decreases thereafter.

The value of R is the difference between the calculated core reactivity at the beginning of the operating cycle and the calculated value of the core reactivity any time later in the cycle where it would be greater than at the beginning. The value of R shall include the potential shutdown margin loss assuming full B_4C settling in all inverted poison tubes present in the core. A new value of R must be determined for each new fuel cycle.

The 0.25% Δk in the expression R + 0.25% Δk is provided as a finite, demonstrable, subcriticality margin. This margin is demonstrated by full withdrawal of the strongest rod and partial withdrawal of an adjacent rod to a position calculated to insert at least R + 0.25% Δk in reactivity. Observation of subcriticality in this condition assures subcriticality with not only the stongest rod fully withdrawn but a margin of at least R + 0.25% Δk beyond this.

2. Reactivity margin - stuck control rods

Specification 3.3.A.2 requires that a rod be taken out of service if it cannot be moved with drive pressure. If the rod is fully inserted and then disarmed electrically, (Note: To disarm the drive electrically, four amphenol type plug connectors are removed from the drive insert and withdrawal solenoids, rendering the drive immovable. This procedure is equivalent to valving out the drive

and is preferred, as drive water cools and minimizes crud accumulation in the drive.), it is in a safe position of maximum contribution to shutdown reactivity. If it is disarmed electrically in a nonfully inserted position, that position shall be consistent with the shutdown reactivity limitation stated in Specification 3.3.A.1. This assures that the core can be shut down at all times with the remaining control rods, assuming the stongest operable control rod does not insert. An allowable pattern for control rods valved out of service, which shall meet the specification, will be available to the operator. The number of rods permitted to be inoperable could be many more than the eight allowed by the specification, particularly late in the operation cycle; however, the occurrence of more than eight could be indicative of a generic control rod drive problem and the reactor will be shut down.

Also if damage within the control rod drive mechanism and in particular, cracks in drive internal housings, cannot be ruled out, then a generic problem affecting a number of drives cannot be ruled out. Circumferential cracks resulting from stress assisted intergranular corrosion have occurred in the collet housing of drives at several BWR's. 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.

3. Rod Position Indication System (RPIS)

Normal control rod position is displayed by two-digit indication to the operator from position 00 to 48. Each even number is a latching position, whereas each odd number provides information while the rod is in motion and input for rod drift annunciation. The LCO provides for the condition where no positive information is displayed for a large portion or all of the rod's travel. In this case the rod is given a full insert signal, individually scrammed and treated as an inoperable rod. Usually only one digit of one or two of a rod's positions is unavailable with a faulty RPIS, and the control rod may be located in a known position.

B. Control Rod Withdrawal

1. Control rod dropout accidents as discussed in Reference 1 can lead to significant core damage. If coupling integrity is maintained, the possibility of a rod dropout accident is eliminated. The overtravel position feature provides a positive check, as only uncoupled drives may reach this position.

Neutron instrumentation response to rod movement provides a verification that the rod is following its drive. Absence of such response to drive movement would indicate an uncoupled condition.

2. The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the extremely remote event of a housing failure. The amount of reactivity which could be added by this small amount of rod withdrawal, which is less than a normal single withdrawal increment, will not contribute to any damage to the primary coolant system. The design basis is given in Section 6.6.1, and the design evaluation is given in Section 6.6.3 of the SAR. This support is not required if the reactor coolant system is at atmospheric pressure, since there would then be no driving force to rapidly eject a drive housing. Additionally, the support is not required if all control rods are fully inserted or if an adequate shutdown margin with one control rod withdrawn has been demonstrated, since the reactor would remain subcritical even in the event of complete ejection of the strongest control rod.

3. Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn could not be worth enough to cause the rod drop accident design limit of 280 cal/gm to be exceeded if they were to drop out of the core in the manner defined for the rod drop accident. These sequences are developed prior to initial operation of the unit following any refueling outage and the requirement that an operator follow these sequences is supervised by the RWM or a second qualified station employee. These sequences are developed to limit reactivity worths of control rods and together with the integral rod velocity limiters and the action of the control rod drive system, limits potential reactivity insertion such that the results of a control rod drop accident will not exceed a maximum fuel energy content of 280 cal/gm. The peak fuel enthalpy of 280 cal/gm is below the energy content at which rapid fuel dispersal and primary system damage have been found to occur based on experimental data as is discussed in Reference 2.

   The analysis of the control rod drop accident was originally presented in Section 7.9.3, 14.2.1.2 and 14.2.1.4 of the SAR. Improvements in analytical capability have allowed a more refined analysis of the control rod drop accident.

   These techniques are described in a topical report (Reference 2) and two supplements (References 3 and 4). In addition, a banked position withdrawal sequence described in Reference 5 has been developed to further reduce incremental rod worths. Method and basis for the rod drop accident analyses are documented in Reference 1.

By using the analytical models described in those reports coupled with conservative or worst-case input parameters, it has been determined that for power levels less than 20% of rated power, the specified limit on insequence control rod or control rod segment worths will limit the peak fuel enthalpy to less than 280 cal/g. Above 20% power even single operator errors cannot result in out-of-sequence control rod worths which are sufficient to reach a peak fuel enthalpy of 280 cal/g should a postulated control rod drop accident accident occur.

The following parameters and worst-case assumptions have been utilized in the analysis to determine compliance with the 280 cal/gm peak fuel enthalpy. Each core reload will be analyzed to show conformance to the limiting parameters.

a. an interassembly local peaking factor (Reference 6).

b. the delayed neutron fraction chosen for the bounding reactivity curve

c. a beginning-of-life Doppler reactivity feedback

d. scram times slower than the Technical Specification rod scram insertion rate (Section 3.3.c.1)

e. the maximum possible rod drop velocity of 3.11 fps

f. the design accident and scram reactivity shape function, and

g. the moderator temperature at which criticality occurs

In most cases the worth of insequence rods or rod segments in conjunction with the actual values of the other important accident analysis parameters described above, would most likely result in a peak fuel enthalpy substantially less than 280 cal/g design limit.

Should a control drop accident result in a peak fuel energy content of 280 cal/g. fewer than 660(7 x 7) fuel rods are conservatively estimated to perforate. This would result in an offsite dose well below the guideline value of 10 CFR 100. For 8 x 8 fuel, fewer than 850 rods are conservatively estimated to perforate, with nearly the same consequences as for the 7 x 7 fuel case because of the rod power differences.

The rod worth minimizer provides automatic supervision to assure that out of sequence control rods will not be withdrawn or inserted; i.e., it limits operator deviations from planned withdrawal sequences (reference SAR Section 7.9). It serves as a backup to procedural control of control rod worth. In the event that the rod worth minimizer is out of service when required, a licensed operator or other qualified technical employee can manually fulfill the control rod pattern conformance function of the rod worth minimizer. In this case, the normal procedural controls are backed up by independent procedural controls to assure conformance.

4. The source range monitor (SRM) system performs no automatic safety system function, i.e., it has no scram function. It does provide the operator with a visual indication of neutron level. This is needed for knowledgeable and efficient reactor startup at low neutron levels. The consequences of reactivity accidents are functions of the initial neutron flux. The requirement of at least 3 counts per second assures that any transient, should it occur, begins at or above the initial value of 10^{-8} of rated power used in the the analyses of transients from cold conditions. One operable SRM channel would be adequate to monitor the approach to criticality using homogeneous patterns of scattered control rod withdrawal. A minimum of two operable SRM's is provided as an added conservatism.

5. The rod block monitor (RBM) is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density during high power operation. Two channels are provided, and one of these may be bypassed from the console for maintenance and/or testing. Tripping of one of the channels will block erroneous rod withdrawal soon enough to prevent fuel damage. This system backs up the operator, who withdraws control rods according to a written sequence. The specified restrictions with one channel out of service conservatively assure that fuel damage will not occur due to rod withdrawal errors when this condition exists. During reactor operation with certain limiting control rod patterns, the withdrawal of a designated single control rod could result one or more fuel rods with MCPR's less than the MCPR fuel cladding integrity safety limit. During use of such patterns it is judged that testing of the RBM system to assure its operability prior to withdrawal of such rods will assure that improper withdrawal does not occur. It is the responsibility of the Nuclear Engineer to identify these limiting patterns and the designated rods either when the patterns are initially established or as they develop due to the occurrence of inoperable control rods in other than limiting patterns.

6. The operability of the Scram Discharge Volume vent and drain valves assures the proper venting and draining of the Volume, so that water accumulation in the Volume does not occur. These specifications provide for the periodic verification that the valves are open, and for the testing of these valves under reactor scram conditions during each Refueling Outage.

C. Scram Insertion Times

The control rod system is analyzed to bring the reactor subcritical at a rate fast enough to prevent fuel damage, i.e., to prevent the MCPR from becoming less than the fuel cladding integrity safety limit.

Analysis of the limiting power transient shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the above specification, provide the required protection, and MCPR remains greater than the fuel cladding integrity safety limit. It is necessary to raise the MCPR operating limit (per Specification 3.5.K) when the average 20% scram insertion time reaches 0.73 seconds on a cycle cumulative basis (overall average of surveillance data to date) in order to comply with assumptions in the implementation procedure for the ODYN transient analysis computer code. The basis for choosing 0.73 seconds is discussed further in the bases for Specification 3.5.K. 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 typically observed time delay of about 210 milliseconds. Approximately 90 milliseconds after neutron flux reaches the trip point, the pilot scram valve solenoid deenergizes and 120 milliseconds later the control rod motion is estimated to actually begin. However, 200 milliseconds rather than 120 milliseconds is conservatively assumed for this time interval in the transient analyses and is also included in the allowable scram insertion times specified in Specification 3.3.C.

The scram times for all control rods will be determined at the time of each refueling outage. A representative sample of control rods will be scram tested during the interval of greater than 16 weeks but not more than 32 weeks.

Scram times of new drives are approximately 2.5 to 3 seconds; lower rates of change in scram times following initial plant operation at power are expected. The test schedule provides reasonable assurance of detection of slow drives before system deterioration beyond the limits of Specification 3.3.C. The program was developed on the basis of the statistical approach outlined below and judgment.

The history of drive performance accumulated to date indicates that the 90% insertion times of new and overhauled drives approximate a normal distribution about the mean which tends to become skewed toward longer scram times as

operating time is accumulated. The probability of a drive not exceeding the mean 90% insertion time by 0.75 seconds is greater than 0.999 for a normal distribution. The measurement of the scram performance of the drives surrounding a drive exceeding the expected range of scram performance will detect local variations and also provide assurance that local scram time limits are not exceeded. Continued monitoring of other drives exceeding the expected range of scram times provides surveillance of possible anomalous performance.

The numerical values assigned to the predicted scram performance are based on the analysis of the Dresden 2 startup data and of data from other BWR's such as Nine Mile Point and Oyster Creek.

The occurrence of scram times w[illegible] the limits, but significantly longer than average, should be [illegible] as an indication of a systematic problem with control rod drive [illegible]cially if the number of drives exhibiting such scram times ex[illegible] eight, the allowable number of inoperable rods.

D. Control Rod Accumulators

The basis for this specification was not described in the [illegible] and is therefore presented in its entirety. Requiring no more t[illegible]e inoperable accumulator in any nine-rod square array is ba[illegible] a series of XY PDQ-4 quarter core calculations of a cold clean core. [illegible]me worst case in a nine-rod withdrawal sequence resulted in a $k_{eff} < 1.0$. Other repeating rod sequences with more rods withdrawn resulted in $k_{eff} > 1.0$. At reactor pressures in excess of 800 psig even those control rods with inoperable accumulators will be able to meet required scram insertion times due to the action of reactor pressure. In addition, they may be normally inserted using the control rod drive hydraulic system. Procedural control will assure that control rods with inoperable accumulators will be spaced in a one-in-nine array rather than grouped together.

E. Reactivity Anomalies

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 may be inferred from the critical rod configuration. As fuel burnup progresses, anomalous behavior in the excess reactivity may be detected by comparison of the critical rod pattern selected base states to the predicted rod inventory at that state. Power operating base conditions provide the most sensitive and directly interpretable data relative to core reactivity. Furthermore, using power operating base conditions permits frequent reactivity comparisons. Requiring a reactivity comparison at the specified frequency assures that a comparison will be made before the core reactivity change exceeds 1% Δk. Deviations in core reactivity greater than 1% Δk are not expected and require thorough evaluation. A 1% reactivity limit is considered safe, since an insertion of the reactivity into the core would not lead to transients exceeding design conditions of the reactor system.

F. Economic Generation Control System

Operation of the facility with the economic generation control system (EGC) (automatic flow control) is limited to the range of 65% to 100% of rated core flow. In this flow range and with reactor power above 20%, the reactor could safely tolerate a rate of change of load of 8 MWe/sec (reference SAR Section 7.3.5).

Limits within the EGC and the flow control system prevent rates of change greater than approximately 4 MWe/sec. When EGC is in operation, this fact will be indicated on the main control room console. The results of initial testing will be provided to the NRC before the onset of routine operation with EGC.

References

1. "Generic Reload Fuel Application", NEDE-24011-P-A"

2. C. J. Paone, R. C. Stirn, and J. A. Wooley, "Rod Drop Accident Analysis for Large BWR's, GE Topical Reports NEDO-10527, March 1972.

3. C. J. Paone, R. C. Stirn and R. M. Young, "Rod Drop Accident Analysis for Large BWR's, Supplement 1. GE Topical Report NEDO-10527, July 1972.

4. J. M. Haun, C. J. Paone, and R. C. Stirn, "Rod Drop Accident Analysis for Large BWR's, Addendum 2. Exposed Cores," Supplement 2, GE Topical Report NEDO-10527, January 1973.

5. C. J. Paone, "Banked position withdrawal sequence, "Licensing topical Report "NEDO-21231, January, 1977.

6. To include the power spike effect caused by gaps between fuel pellets.

* Approved revision number at time reload fuel analyses are performed.

3.4/4.4 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to the operating status of the standby liquid control system.

Objective:

To assure the availability of an independent reactivity control mechanism.

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the periodic testing requirements for the standby liquid control system.

Objective:

To verify the operability of the standby liquid control system.

SPECIFICATIONS

A. Normal Operation

During periods when fuel is in the reactor and prior to startup from a cold condition, the standby liquid control system shall be operable except as specified in Specification 3.4.B. This system need not be operable when the reactor is in the cold shutdown condition, all control rods are fully inserted, and Specification 3.3.A is met.

A. Normal Operation

The operability of the standby liquid control system shall be verified by performance of the following tests:

1. At least once per month

   Demineralized water shall be recycled to the test tank. Pump minimum flow rate of 40 gpm shall be verified against a system head of 1275 psig.

2. At least once during each operating cycle

   Manually initiate the system, except the explosion valves and pump solution in the recirculation path, to demonstrate that the pump suction line from the storage tank is not plugged.

Explode two of six charges or two of four charges manufactured in the same batch using the permanent system wiring to verify proper function. Then install the untested charges in the explosion valves.

Demineralized water shall be injected via a test connection into the reactor vessel to test that valves (except explosion valves) not checked by the recirculation test are not clogged.

Test that the setting of the system pressure relief valves is between 1455 and 1545 psig.

3. Disassemble and inspect one explosion valve so that it can be established that the valve is not clogged. Both valves shall be inspected in the course of two operating cycles.

B. Operation with Inoperable Components

From and after the date that a redundant component is made or found to be inoperable, Specification 3.4.A shall be considered fulfilled and continued operation permitted provided that the component is returned to an operable condition within 7 days.

B. Operation with Inoperable Components

When a component becomes inoperable, its redundant component shall be demonstrated to be operable immediately and daily thereafter.

C. Liquid Poison Tank-Boron Concentration

The liquid poison tank shall contain a boron-bearing solution of at least 3733 gallons of at least 14 WT percent sodium pentaborate Decahydrate ($N_aB_{10}O_{16}$ - $10H_2O$) at all times when the standby liquid control system is required to be operable and the solution temperature shall not be less than the temperature presented in Figure 3.4-2.

C. Liquid Poison Tank-Boron Concentration

The availability of the proper boron-bearing solution shall be verified by performance of the following tests:

1. At least once per month

   Boron concentration shall be determined. In addition, the boron concentration shall be determined any time water or boron are added or if the solution temperature drops below the limits specified by Figure 3.4-2.

2. At least once per day

   Solution volume shall be checked.

3. At least once per day

   The solution temperature shall be checked.

D. If Specifications 3.4.A through C are not met, an orderly shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

3.4 LIMITING CONDITIONS FOR OPERATION BASES

A. The design objective of the standby liquid control system is to provide the capability of bringing the reactor from full power to a cold, xenon-free shutdown assuming that none of the withdrawn control rods can be inserted. To meet this objective, the liquid control system is designed to inject a quantity of boron which produces a concentration of no less than 600 ppm of boron in the reactor core in approximately 90 to 120 minutes with imperfect mixing. A boron concentration of 600 ppm in the reactor core is required to bring the reactor from full power to 3% Δk or more subcritical condition considering the hot to cold reactivity swing, xenon poisoning and an additional margin in the reactor core for imperfect mixing of the chemical solution in the reactor water. A normal quantity of 3,470 gallons of solution having a 13.4% sodium pentaborate concentration is required to meet this shutdown requirement.

The time requirement (90 to 120) minutes for insertion of the boron solution was selected to override the rate of reactivity insertion due to cooldown of the reactor following the xenon poison peak. For a required pumping rate of 39 gpm, the maximum storage volume of the boron solution is established as 4,875 gallons (195 gallons are contained below the pump suction and, therefore, cannot be inserted).

Boron concentration, solution temperature, and volume are checked on a frequency to assure a high reliability of operation of the system should it ever be required. Experience with pump operability indicates that monthly testing is adequate to detect if failures have occurred.

The only practical time to test the standby liquid control system is during a refueling outage and by initiation from local stations. Components of the system are checked periodically as described above and make a functional test of the entire system on a frequency of less than once each refueling outage unnecessary. A test of explosive charges from one manufacturing batch is made to assure that the charges are satisfactory. A continual check of the firing circuit continuity is provided by pilot lights in the control room.

B. Only one of two standby liquid control pumping circuits is needed for proper operation 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. Assurance that the remaining system will perform its intended function and that the reliability of the system is good is obtained by demonstrating operation of the pump in the operable circuit at least once daily. A

reliability analysis indicates that the plant can be operated safely in this manner for 7 days.

C. The solution saturation temperature of 13% sodium pentaborate, by weight, is 59°F. The solution shall be kept at least 10°F above the saturation temperature to guard against boron precipitation. The 10°F margin is included in Figure 3.3-1. Temperature and liquid level alarms for the system are annunciated in the control room.

Pump operability is checked on a frequency to assure a high reliability of operation of the system should it ever be required.

Once the solution has been made up, boron concentration will not vary unless more boron or more water is added. Level indication and alarm indicate whether the solution volume has changed, which might indicate a possible solution concentration change. Considering these factors, the test interval has been established.

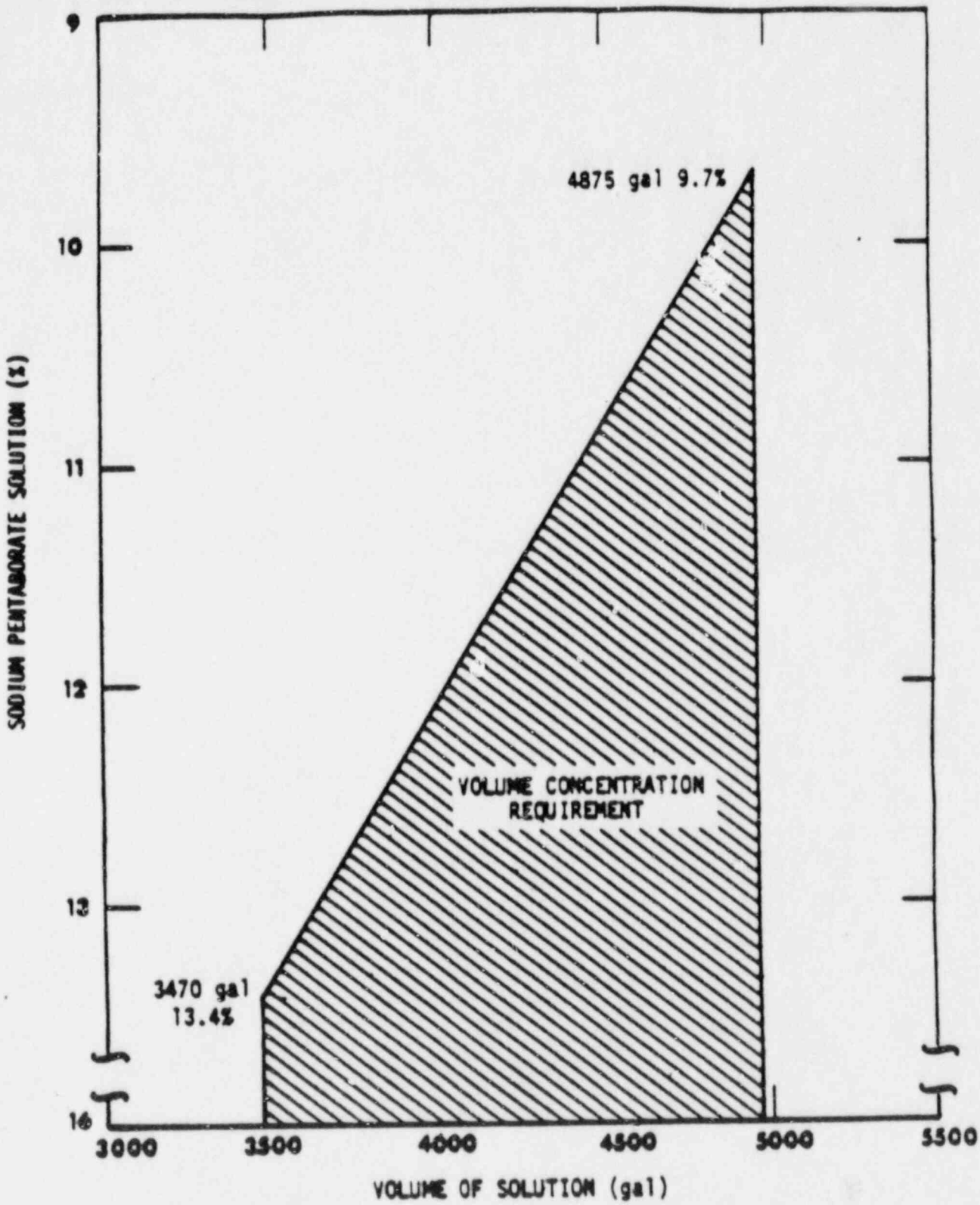


FIGURE 3.4-1

STANDBY LIQUID CONTROL
SOLUTION REQUIREMENTS

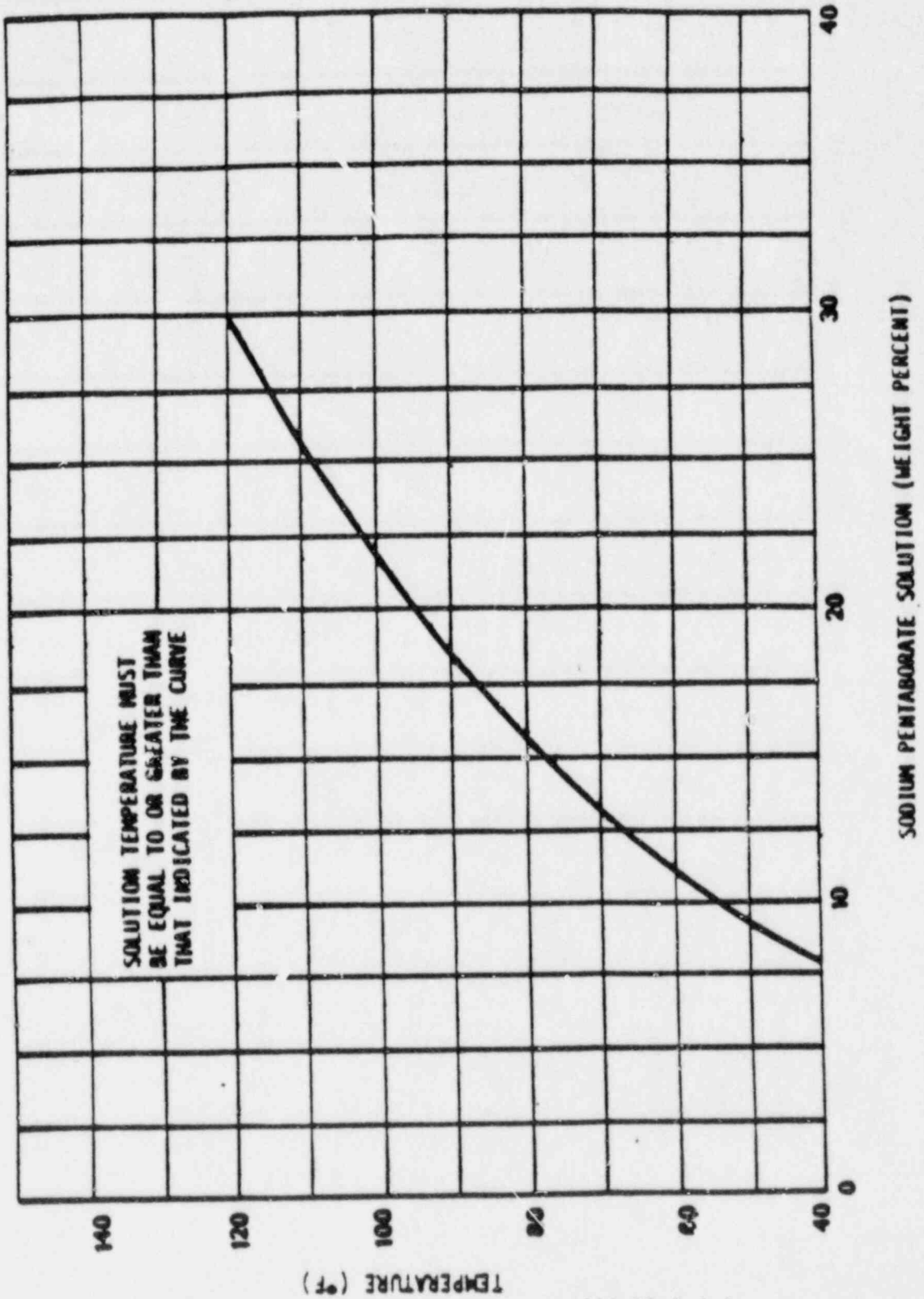


FIGURE 3.4-2

SODIUM PENTABORATE SOLUTION
TEMPERATURE REQUIREMENTS

3.5/4.5 CORE AND CONTAINMENT COOLING SYSTEMS

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to the operational status of the emergency cooling subsystems.

Objective:

To assure adequate cooling capability for heat removal in the event of a loss-of-coolant accident or isolation from the normal reactor heat sink.

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to periodic testing of the emergency cooling subsystems.

Objective:

To verify the operability of the core and containment cooling subsystems

SPECIFICATIONS

A. Core Spray Subsystems and the LPCI Mode of the RHR System

1. Both core spray subsystems shall be operable whenever irradiated fuel is in the reactor vessel and prior to reactor startup from a cold condition.

A. Core Spray Subsystems and the LPCI Mode of the RHR System

Surveillance of the core spray subsystems and the LPCI mode of the RHR system shall be performed as follows:

1. Core Spray Subsystem Testing

	Item	Frequency
a.	Simulated automatic actuation	Each refueling
b.	Flow rate test - core spray pumps shall deliver at least 4500 gpm against a system head corresponding to a reactor vessel pressure of 90 psig	After pump maintenance and every 3 months
c.	Pump operability	Once/month
d.	Motor-operated valve	Once/month

e. Core spray header Δ p instrumentation	
check	Once/day
calibrate	Once/3 months
test	Once/3 months
f. Logic system functional test	Once/Each refueling outage

2. From and after the date that one of the core spray subsystems is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 7 days unless such subsystem is sooner made operable, provided that during such 7 days all active components of the other core spray subsystem and the LPCI mode of the RHR system and the diesel generators required for operation of such components if no external source of power were available shall be operable.

2. When it is determined that one core spray subsystem is inoperable, the operable core spray subsystem and the LPCI mode of the RHR system shall be demonstrated to be operable immediately. The operable core spray subsystem shall be demonstrated to be operable daily thereafter.

3. The LPCI mode of the RHR system shall be operable whenever irradiated fuel is in the reactor vessel and prior to reactor startup from a cold condition.

3. LPCI mode of the RHR system testing shall be as specified in Specifications 4.5.A.1.a, b, c, d, and f, except that each LPCI division (two RHR pumps per division) shall deliver at least 9000 gpm against a system head corresponding to a reactor vessel pressure of 20 psig, with a minimum flow valve open.

4. From and after the date that one of the RHR pumps is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 30 days unless such pump is sooner made operable, provided that during such 30 days the remaining active components of the LPCI mode of the RHR, containment cooling

4. When it is determined that one of the RHR pumps is inoperable, the remaining active components of the LPCI mode of the RHR, containment cooling mode of the RHR, and both core spray subsystems shall be demonstrated to be operable immediately and the operable RHR pumps daily thereafter.

mode of the RHR, all active components of both core spray subsystems, and the diesel generators required for operation of such components if no external source of power were available shall be operable.

5. From and after the date that the LPCI mode of the RHR system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 7 days unless it is sooner made operable, provided that during such 7 days all active components of both core spray subsystems, the containment cooling mode of the RHR (including two RHR pumps), and the diesel generators required for operation of such components if no external source of power were available shall be operable.

6. If the requirements of Specification 3.5.A cannot be met, an orderly shutdown of the reactor shall be initiated, and the reactor shall be in the cold shutdown condition within 24 hours.

B. Containment Cooling Mode of the RHR System

1. a. Both loops of the containment cooling mode of the RHR system, as defined in the bases for Specification 3.5.B, shall be operable whenever irradiated fuel is in the reactor vessel and prior to reactor startup from a cold condition.

5. When it is determined that the LPCI mode of the RHR system is inoperable, both core spray subsystems, the containment cooling mode of the RHR shall be demonstrated to be operable immediately and daily thereafter.

B. Containment Cooling Mode of the RHR System

Surveillance of the containment cooling mode of the RHR system shall be performed as follows:

1. RHR service water subsystem testing:

	Item	Frequency
a.	Pump and valve operability	Once/3 months

1. b. From the effective date of this amendment until July 1, 1982, the "A" loop of the containment cooling mode of the RHR system for each reactor may share the Unit 2 "A" and "B" RHR service water pumps using cross tie line 1/2-10124-16"-D. Consequently, the requirements of Specifications 3.5.B.2 and 3.5.B.3 will impose the corresponding surveillance testing of equipment associated with both reactors if the shared RHR service water pump or pumps, or the cross tie line, are made or found to be inoperable.

2. From and after the date that one of the RHR service water pumps is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 30 days unless such pump is sooner made operable, provided that during such 30 days all other active components of the containment cooling mode of the RHR system are operable.

3. From and after the date that one loop of the containment cooling mode of the RHR system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 7 days unless such subsystem is sooner made operable, provided that all active components of the other loop of the containment cooling mode of the RHR system, both core spray subsystems, and both diesel generators required for operation of such components if no external source of power were available, shall be operable.

b.	Flow rate test - each RHR service water pump shall deliver at least 3500 gpm against a pressure of 198 psig	After pump maintenance and every 3 months
c.	A logic system functional test	Each refueling outage

2. When it is determined that one RHR service water pump is inoperable, the remaining components of that loop and the other containment cooling loop of the RHR system shall be demonstrated to be operable immediately and daily thereafter.

3. When one loop of the containment cooling mode of the RHR system becomes inoperable, the operable loop shall be demonstrated to be operable immediately, and daily thereafter.

4. Containment cooling spray loops are required to be operable when the reactor water temperature is greater than 212° F and prior to reactor startup from a cold condition. Continued reactor operation is permitted provided that a maximum of one drywell spray loop may be inoperable for 30 days when the reactor water temperature is greater than 212° F.

5. If the requirements of 3.5.B cannot be met, an orderly shutdown shall be initiated, and the reactor shall be in a cold shutdown condition within 24 hours.

4. During each 5-year period, an air test shall be performed on the drywell spray headers and nozzles and a water spray test performed on the torus spray header and nozzles.

C. HPCI Subsystem

1. The HPCI subsystem shall be operable whenever the reactor pressure is greater than 90 psig, irradiated fuel is in the reactor vessel, and prior to reactor startup from a cold condition.

2. From and after the date that the HPCI subsystem is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 7 days unless such subsystem is sooner made operable, provided that during such 7 days all active components of the automatic pressure relief subsystems, the core spray subsystems, LPCI mode of the RHR system, and the RCIC system are operable.

C. HPCI Subsystem

Surveillance of HPCI subsystem shall be performed as follows:

1. HPCI subsystem testing shall be as specified in Specifications 4.5.A.1.a, b, c, and d, except that the HPCI pump shall deliver at least 5000 gpm against a system head corresponding to a reactor vessel pressure of 1150 psig to 150 psig, and a logic system functional test shall be performed during each refueling outage.

2. When it is determined that the HPCI subsystem is inoperable, the LPCI mode of the RHR system, both core spray subsystems, the automatic pressure relief subsystem, and the RCIC system shall be demonstrated to be operable immediately. The RCIC system shall be demonstrated to be operable daily thereafter. Daily demonstration of the automatic pressure relief subsystem

operability is not required provided that two feedwater pumps are operating at levels above 300 MWe; and one feedwater pump is operating as normally required with one additional feedwater pump operable at power levels less than 300 MWe.

3. If the requirements of Specification 3.5.C cannot be met, an orderly shutdown shall be initiated, and the reactor pressure shall be reduced to 90 psig within 24 hours.

D. Automatic Pressure Relief Subsystems

1. The automatic pressure relief subsystem shall be operable whenever the reactor pressure is greater than 90 psig, irradiated fuel is in the reactor vessel and prior to reactor startup from a cold condition.

2. From and after the date that two of the five relief valves of the automatic pressure relief subsystem are made or found to be inoperable when the reactor is pressurized above 90 psig with irradiated fuel in the reactor vessel, reactor operation is permissible only during the succeeding 7 days unless repairs are made and provided that during such time the HPCI subsystem is operable.

D. Automatic Pressure Relief Subsystems

Surveillance of the automatic pressure relief subsystem shall be performed as follows:

1. The following surveillance shall be carried out on a six-month surveillance interval:

   a. With the reactor at pressure each relief valve shall be manually opened. Relief valve opening shall be verified by a compensating turbine bypass valve or control valve closure.

2. A logic system functional test shall be performed each refueling outage.

2. a. Plant operation shall be in accordance with 3.5.D.2 above except that, for the current operating cycle 5, four of the five relief valves of the ADS are required to be operable. In subsequent operating cycles, operation shall be in accordance with 3.5.D.2.

3. If the requirements of Specification 3.5.D cannot be met, an orderly shutdown shall be initiated and the reactor pressure shall be reduced to 90 psig within 24 hours.

E. Reactor Core Isolation Cooling System

1. The RCIC system will be operable whenever the reactor pressure is greater than 150 psig, irradiated fuel is in the reactor vessel, and prior to startup from a cold condition.

2. From and after the date that the RCIC system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 7 days unless such system is sooner made operable, provided that during such 7 days all active components of the HPCI system are operable.

3. A simulated automatic initiation which opens all pilot valves shall be performed each refueling outage.

4. When it is determined that two valves of the automatic pressure relief subsystem are inoperable, the HPCI shall be demonstrated to be operable immediately.

E. Reactor Core Isolation Cooling System

Surveillance of the RCIC system shall be performed as follows:

1. RCIC system testing shall be as specified in Specification 4.5.A.1.a, b, c, and d, except that the RCIC pump shall deliver at least 400 gpm against a system head corresponding to a reactor vessel pressure of 1150 psig to 150 psig, and a logic system functional test shall be run during each refueling outage.

2. When it is determined that the RCIC system is inoperable, the HPCI system shall be demonstrated to be operable immediately and daily thereafter.

3. If the requirements of Specification 3.5.E.1 and 3.5.E.2 cannot be met, an orderly shutdown shall be initiated and the reactor pressure shall be reduced to 90 psig within 24 hours.

   During the period November 6 through November 20, 1976 the unit may be started up with the RCIC inoperable provided that (1) the facility is not more than 7 days with the RCIC inoperable and (2) all the HPCI system active components are demonstrated to be operable immediately after startup and daily thereafter.

F. Minimum Core and Containment Cooling System Availability

   1. Any combination of inoperable components in the core and containment cooling systems shall not defeat the capability of the remaining operable components to fulfill the core and containment cooling functions.

   2. When irradiated fuel is in the reactor vessel and the reactor is in the cold shutdown condition, all low-pressure core and containment cooling systems may be inoperable provided no work is being done which has the potential for draining the reactor vessel.

F. Minimum Core and Containment Cooling System Availability

   Surveillance requirements to assure that minimum core and containment cooling systems are available have been specified in Specification 4.2.B.

3. When irradiated fuel is in the reactor and the vessel head is removed, the suppression chamber may be drained completely and no more than one control rod drive housing opened at any one time provided that the spent fuel pool gate is open and the fuel pool water level is maintained at a level of greater than 33 feet above the bottom of the pool. Additionally, a minimum condensate storage reserve of 230,000 gallons shall be maintained, no work shall be performed in the reactor vessel while a control rod drive housing is blanked following removal of the control rod drive, and a special flange shall be available which can be used to blank an open housing in the event of a leak.

4. When irradiated fuel is in the reactor and the vessel head is removed, work that has the potential for draining the vessel may be carried on with less than 112,200 ft^3 of water in the suppression pool, provided that: (1) the total volume of water in the suppression pool, refueling cavity, and the fuel storage pool above the bottom of the fuel pool gate is greater than 112,200 ft^3; (2) the fuel storage pool gate is removed; (3) the low-pressure core and containment cooling systems are operable; and (4) the automatic mode of the drywell sump pumps is disabled.

G. Maintenance of Filled Discharge Pipe

1. Whenever core spray, LPCI mode of the RHR, HPCI, or RCIC are required to be operable, the discharge piping from the pump discharge of these systems to the last check valves shall be filled.

2. The discharge pipe pressure for Core Spray and LPCI mode of RHR shall be maintained at greater than 40 psig and less than 90 psig. If pressure in any of these systems is less than 40 psig or greater than 90 psig, this condition shall be alarmed in the control room and immediate corrective action taken. If the discharge pipe pressure is not within these limits in 12 hours after the occurrence, an orderly shutdown shall be initiated, and the reactor shall be in a cold shutdown condition within 24 hours after initiation.

3. Filled discharge piping for HPCI and RCIC systems is ensured by maintaining the level in the Contaminated Condensate Storage Tanks (CCST's) at or above 9.5 feet. If the CCST level falls below 9.5 feet, restore the level within 12 hours or line up both HPCI and RCIC to take a suction from the torus per 4.5.G.3.

G. Maintenance of Filled Discharge Pipe

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

1. Every month prior to the testing of the LPCI mode of the RHR and core spray ECCS, the discharge piping of these systems shall be vented from the high point and water flow observed.

2. Following any period where HPCI, RCIC, LPCI mode of the RHR or core spray have been out of service and drained for maintenance, the discharge piping of the inoperable system shall be vented from the high point prior to the return of the system to service.

3. Whenever the HPCI or RCIC system is lined up to take suction from the torus, the discharge piping of the HPCI and RCIC shall be vented from the high point of the system and water flow observed every 24 hours.

4. The pressure switches which monitor the discharge lines and the discharge of the fill system pump to ensure that they are full shall be functionally tested every month and calibrated every 3 months. The pressure switches shall be set to alarm at a decreasing pressure of $\geq$ 40 psig and an increasing pressure of $\leq$ 90 psig.

H. Condensate Pump Room Flood Protection

1. The systems installed to prevent or mitigate the consequences of flooding of the condensate pump room shall be operable prior to startup of the reactor.

H. Condensate Pump Room Flood Protection

1. The following surveillance requirements shall be observed to assure that the condensate pump room flood protection is operable.

   a. The piping and electrical penetrations, bulkhead doors, and submarine doors for the vaults containing the RHR service water pumps and diesel generator cooling pumps shall be checked during each operating cycle by pressurizing to 15 $\pm$ 2 psig and checking for leaks using a soap bubble solution. The criteria for acceptance shall be no visible leakage through the soap bubble solution.

   b. During each operating cycle, the following flood protection level switches shall be functionally tested to give the following control room alarms:

      1) turbine building equipment drain sump high level.

      2) vault high level

c. The RHR service water vault sump pump discharge check valves outside the vault shall be tested for integrity, using clean demineralized water, at least once per operating cycle.

d. The condenser pit 5-foot trip circuits for each channel shall be checked once a month. A logic system functional test shall be performed during each refueling outage.

2. The condenser pit water level switches shall trip the condenser circulating water pumps and alarm in the control room if water level in the condenser pit exceeds a level of 5 feet above the pit floor. If a failure occurs in one of these trip and alarm circuits, the failed circuit shall be immediately placed in a trip condition and reactor operation shall be permissible for the following 7 days unless the circuit is sooner made operable.

3. If Specification 3.5.H.1 and 2 cannot be met, reactor startup shall not commence or if operating an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 24 hours.

I. Average Planar LHGR

During steady-state power operation, the average linear heat generation rate (APLHGR) of all the rods in any fuel assembly, as a function of average planar exposure, at any axial location, shall not exceed the maximum average planar LHGR shown in Figure 3.5-1. If at any time during operation it is determined by normal surveillance that the limiting value for APLHGR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the APLHGR is not returned to within the prescribed limits within 2 hours, the reactor shall be brought to the cold shutdown condition within 36 hours. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

I. Average Planar LHGR

Daily during steady-state operation above 25% rated thermal power, the average planar LHGR shall be determined.

J. Local LHGR

During steady-state power operation, the linear heat generation rate (LHGR) of any rod in any fuel assembly at any axial location shall not exceed the maximum allowable LHGR. If at any time during operation it is determined by normal surveillance that the limiting value for LHGR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the LHGR is not returned to within the prescribed limits within 2 hours, the reactor shall be brought to the cold shutdown condition within 36 hours. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits. Maximum allowable LHGR is 13.4 kW/ft for fuel types P8X8R and BP8X8R. For fuel types GE8X8E and GE8X8EB the maximum allowable LHGR is 14.4 kW/ft.

J. Local LHGR

Daily during steady-state power operation above 25% of rated thermal power, the local LHGR shall be determined.

K. Minimum Critical Power Ratio (MCPR)

During steady-state operation at rated core flow, MCPR shall be greater than or equal to:

1.33 for $\tau_{AVE} \leq 0.71$ sec

1.37 for $\tau_{AVE} \geq 0.86$ sec

$0.278 \ \tau_{AVE} + 1.131$

for $0.71 \text{ sec} \leq \tau_{AVE} \leq 0.86$ sec

where τ_{AVE} = mean 20% scram insertion time for all surveillance data from specification 4.3.C which has been generated in the current cycle.

For core flows other than rated, these nominal values of MCPR shall be increased by a factor of k_f where k_f is as shown in Figure 3.5-2. If any time during operation it is determined by normal surveillance that the limiting value for MCPR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the steady-state MCPR is not returned to within the prescribed limits within 2 hours, the reactor shall be brought to the cold shutdown condition within 36 hours. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

K. Minimum Critical Power Ratio (MCPR)

The MCPR shall be determined daily during steady-state power operation above 25% of rated thermal power.

3.5 LIMITING CONDITIONS FOR OPERATION BASES

A. Core Spray and LPCI Mode of the RHR System

This specification assures that adequate emergency cooling capability is available whenever irradiated fuel is in the reactor vessel.

Based on the loss-of-coolant analytical methods described in General Electric Topical Report NEDC-31345P core cooling systems provide sufficient cooling to the core to dissipate the energy associated with the loss-of-coolant accident, to limit calculated fuel cladding temperature to less than 2200°F, to assure that core geometry remains intact, to limit cladding metal-water reaction to less than 1%, and to limit the calculated local metal-water reaction to less than 17%.

The limiting conditions of operation in Specifications 3.5.A.1 through 3.5.A.6 specify the combinations of operable subsystems to assure the availability of the minimum cooling systems noted above. Under these limiting conditions of operation, increased surveillance testing of the remaining ECCS systems provides assurance that adequate cooling of the core will be provided during a loss-of-coolant accident.

Core spray distribution has been shown, in full-scale tests of systems similar in design to that of Quad-Cities 1 and 2, to exceed the minimum requirements by at least 25%. In addition, cooling effectiveness has been demonstrated at less than half the rated flow in simulated fuel assemblies with heater rods to duplicate the decay heat characteristics of irradiated fuel. The accident analysis is additionally conservative in that no credit is taken for spray cooling of the reactor core before the internal pressure has fallen to 90 psig.

The LPCI mode of the RHR system is designed to provide emergency cooling to the core by flooding in the event of a loss-of-coolant accident. This system functions in combination with the core spray system to prevent excessive fuel cladding temperature. The LPCI mode of the RHR system in combination with the core spray subsystem provides adequate cooling for break areas of approximately 0.05 ft^2 up to and including 4.26 ft^2, the latter being the double-ended recirculation line break with the equalizer line between the recirculation loops closed without assistance from the high-pressure emergency core cooling subsystems.

The allowable repair times are established so that the average risk rate for repair would be no greater than the basic risk rate. The method and concept are described in Reference 3. Using the results developed in this reference, the repair period is found to be less than

half the test interval. This assumes that the core spray subsystems and LPCI constitute a one-out-of-two system; however, the combined effect of the two systems to limit excessive cladding temperature must also be considered. The test interval specified in Specification 4.5 was 3 months. Therefore, an allowable repair period which maintains the basic risk considering single failures should be less than 30 days, and this specification is within this period. For multiple failures, a shorter interval is specified; to improve the assurance that the remaining systems will function, a daily test is called for. Although it is recognized that the information given in Reference 1 provides a quantitative method to estimate allowable repair times, the lack of operating data to support the analytical approach prevents complete acceptance of this method at this time. Therefore, the times stated in the specific items were established with due regard to judgment.

Should one core spray subsystem become inoperable, the remaining core spray subsystem and the entire LPCI mode of the RHR system are available should the need for core cooling arise. To assure that the remaining core spray and the LPCI mode of the RHR system are available, they are demonstrated to be operable immediately. This demonstration includes a manual initiation of the pumps and associated valves. Based on judgments of the reliability of the remaining systems, i.e., the core spray and LPCI, a 7-day repair period was obtained.

Should the loss of one RHR pump occur, a nearly full complement of core and containment cooling equipment is available. Three RHR pumps in conjunction with the core spray subsystem will perform the core cooling function. Because of the availability of the majority of the core cooling equipment, which will be demonstrated to be operable, a 30-day repair period is justified. If the LPCI mode of the RHR system is not available, at least two RHR pumps must be available to fulfill the containment cooling function. The 7-day repair period is set on this basis.

B. RHR Service Water

The containment cooling mode of the RHR system is provided to remove heat energy from the containment in the event of a loss-of-coolant accident. For the flow specified, the containment long-term pressure is limited to less than 8 psig and is therefore more than ample to provide the required heat-removal capability (reference SAR Section 5.2.3.2).

The Containment Cooling mode of the RHR System consists of two loops. Each loop consists of 1 Heat Exchanger, 2 RHR Pumps, and the associated valves, piping, electrical equipment, and instrumentation. The "B" loop on each unit contains 2 RHR Service Water Pumps. During the period from November 24, 1981, to July 1, 1982, the "A" loop on each unit may utilize the "A" and "B" RHR Service Water Pumps from Unit 2 via a cross-tie line. After July 1, 1982, each "A" loop will contain 2 RHR Service Water Pumps. Either set of equipment is capable of performing the containment cooling function. Loss of one RHR service water pump does not seriously jeopardize the containment cooling capability, as any one of the remaining three pumps can satisfy the cooling requirements. Since there is some redundancy left, a 30-day repair period is adequate. Loss of one loop of the containment cooling mode of the RHR system leaves one remaining system to perform the containment cooling function. The operable system is demonstrated to be operable each day when the above condition occurs. Based on the fact that when one loop of the containment cooling mode of the RHR system becomes inoperable, only one system remains, which is tested daily, a 7-day repair period was specified.

C. High-Pressure Coolant Injection

The high-pressure coolant injection subsystem is provided to adequately cool the core for all pipe breaks smaller than those for which the LPCI mode of the RHR system or core spray subsystems can protect the core.

The HPCI meets this requirement without the use of offsite electrical power. For the pipe breaks for which the HPCI is intended to function, the core never uncovers and is continuously cooled, thus no cladding damage occurs (reference SAR Section 6.2.5.3). The repair times for the limiting conditions of operation were set considering the use of the HPCI as part of the isolation cooling system.

D. Automatic Pressure Relief

The relief valves of the automatic pressure relief subsystem are a backup to the HPCI subsystem. They enable the core spray subsystem and LPCI mode of the RHR system to provide protection against the small pipe break in the event of HPCI failure by depressurizing the reactor vessel rapidly enough to actuate the core spray subsystems or LPCI mode of the RHR system. The core spray subsystem and/or the LPCI mode of the RHR system provide sufficient flow of coolant to limit fuel cladding temperatures to less than 2200°F, to assure that core geometry remains intact, to limit the core wide clad metal-water reaction to less than 1%, and to limit the calculated local metal-water reaction to less than 17%.

analyses have shown that only four of the five valves in the automatic depressurization system are required to operate. Loss of one of the relief valves does not significantly affect the pressure-relieving capability, therefore continued operation is acceptable provided the appropriate MAPLHGR reduction factor is applied to assure compliance with the 2200°F PCT limit. Loss of more than one relief valve significantly reduces the pressure relief capability of the ADS: thus, a 7 day repair period is specified with the HPCI available, and a 24 hour repair period with the HPCI unavailable.

E. RCIC

The RCIC system is provided to supply continuous makeup water to the reactor core when the reactor is isolated from the turbine and when the feedwater system is not available. Under these conditions the pumping capacity of the RCIC system is sufficient to maintain the water level above the core without any other water system in operation. If the water level in the reactor vessel decreases to the RCIC initiation level, the system automatically starts. The system may also be manually initiated at any time.

The HPCI system provides an alternate method of supplying makeup water to the reactor should the normal feedwater become unavailable. Therefore, the specification calls for an operability check of the HPCI system should the RCIC system be found to be inoperable.

F. Emergency Cooling Availability

The purpose of Specification 3.5.F is to assure a minimum of core cooling equipment is available at all times. If, for example, one core spray were out of service and the diesel which powered the opposite core spray were out of service, only two RHR pumps would be available. Likewise, if two RHR pumps were out of service and two RHR service water pumps on the opposite side were also out of service no containment cooling would be available. It is during refueling outages that major maintenance is performed and during such time that all low-pressure core cooling systems may be out of service. This specification provides that should this occur, no work will be performed on the primary system which could lead to draining the vessel. This work would include work on certain control rod drive components and recirculation systems. Thus, the specification precludes the events which could require core cooling. Specification 3.9 must also be consulted to determine other requirements for the diesel generators.

Quad-Cities Units 1 and 2 share certain process systems such as the makeup demineralizers and the radwaste system and also some safety systems such as the standby gas treatment system, batteries, and diesel generators. All of these systems have been sized to perform their intended function considering the simultaneous operation of both units.

These technical specifications contain only a single reference to the operability and surveillance requirements for the shared safety-related features of each plant. The level of operability for one unit must be maintained independently of the status of the other. For example, a diesel (1/2 diesel) which is shared between Units 1 and 2 would have to be operable for continuing Unit 1 operation even if Unit 2 were in a cold shutdown condition and needed no diesel power.

Specification 3.5.F.3 provides that should this occur, no work will be performed which could preclude adequate emergency cooling capability being available. Work is prohibited unless it is in accordance with specified procedures which limit the period that the control rod drive housing is open and assures that the worst possible loss of coolant resulting from the work will not result in uncovering the reactor core. Thus, this specification assures adequate core cooling. Specification 3.9 must be consulted to determine other requirements for the diesel generator.

G. Maintenance of Filled Discharge Pipe

If the discharge piping of the core spray, LPCI mode of the RHR, HPCI, and RCIC are not filled, a water hammer can develop in this piping, threatening system damage and thus the availability of emergency cooling systems when the pump and/or pumps are started. An analysis has been done which shows that if a water hammer were to occur at the time emergency cooling was required, the systems would still perform their design function. However to minimize damage to the discharge systems and to ensure added margin in the operation of these systems, this technical specification requires the discharge lines to be filled whenever the system is in an operable condition.

Specification 3.5.F.4 provides assurance that an adequate supply of coolant water is immediately available to the low-pressure core cooling systems and that the core will remain covered in the event of a loss-of-coolant accident while the reactor is depressurized with the head removed.

H. Condensate Pump Room Flood Protection

See Specification 3.5.H

I. Average Planar LHGR

This specification assures that the peak cladding temperature following the postulated design-basis loss-of-coolant accident will not exceed the 2200°F limit specified in the 10 CFR 50, Appendix K 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 secondarily dependent 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 cladding temperature by less than ± 20°F relative to the peak temperature for a typical fuel design, the limit on the average planar LHGR is sufficient to assure that calculated temperatures are below the limit. The maximum average planar LHGR's shown in Figure 3.5-1 are based on calculations employing the models described in Reference 2.

The Average Planar Linear Heat Generation Rate (APLHGR) also serves a secondary function which is to assure fuel rod mechanical integrity.

J. Local LHGR

This specification assures that the maximum linear heat-generation rate in any rod is less than the design linear heat-generation rate even if fuel pellet densification is postulated. The power spike penalty is discussed in Reference 2 and 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 LHGR due to power spiking. No penalty is required in Specification 3.5.L because it has been accounted for in the reload transient analyses by increasing the calculated peak LHGR by 2.2%.

K. Minimum Critical Power Ratio (MCPR)

The steady state values for MCPR specified in this specification were selected to provide margin to accommodate transients and uncertainties in monitoring the core operating state as well as uncertainties in the critical power correlation itself. These values also assure that operation will be such that the initial condition assumed for the LOCA analysis plus two percent for uncertainty is satisfied. For any of the special set of transients or disturbances caused by single operator error or single equipment malfunction, it is required that design analyses initialized at this steady-state operating limit yield a MCPR of not less than that specified in Specification 1.1.A at any time during the transient, assuming instrument trip settings given in Specification 2.1. For analysis of the thermal consequences of these transients, the value of MCPR stated in this specification for the limiting condition of operation bounds the initial value of MCPR assumed to exist prior to the initiation of the transients. This initial condition, which is used in the transient analyses, will preclude violation of the fuel cladding integrity safety limit. Assumptions and methods used in calculating the required steady state MCPR limit for each reload cycle are documented in References 2 and 4. The results apply with increased conservatism while operating with MCPR's greater than specified.

The most limiting transients with respect to MCPR are generally:

a) Rod withdrawal error

b) Load rejection or turbine trip without bypass

c) Loss of feedwater heater

The MCPR Operating Limit reflects an increase of 0.03 over the most limiting transient to allow continued operation with one feedwater heater out of service.

Several factors influence which of these transients results in the largest reduction in critical power ratio such as the specific fuel loading, exposure, and fuel type. The current cycle's reload licensing analyses specifies the limiting transients for a given exposure increment for each fuel type. The values specified as the Limiting Condition of Operation are conservatively chosen to bound the most restrictive over the entire cycle for each fuel type.

The need to adjust the MCPR operating limit as a function of scram time arises from the statistical approach used in the implementation of the ODYN computer code for analyzing rapid pressurization events. Generic statistical analyses were performed for plant groupings of similar design which considered the statistical variation in several parameters (initial power level, CRD scram insertion time, and model uncertainty). These analyses (which are described further in Reference 4) produced generic Statistical Adjustment Factors which have been applied to plant and cycle specific ODYN results to yield operating limits which provide a 95% probability with 95% confidence that the limiting pressurization event will not cause MCPR to fall below the fuel cladding integrity safety limit.

For core flow rates less than rated, the steady state MCPR is increased by the formula given in the specification. This ensures that the MCPR will be maintained greater than that specified in Specification 1.1.A even in the event that the motor-generator set speed controller causes the scoop tube positioner for the fluid coupler to move to the maximum speed position.

References

1. "SAFER/GESTR-LOCA Loss of Coolant Analysis for QuadCities Nuclear Power Station Units 1 & 2" NEDC-31345P.*

2. "Generic Reload Fuel Application," NEDE-24011-P-A**

3. I. M. Jacobs and P. W. Marriott, GE Topical Report APED 5736, "Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards," April, 1969.

4. "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors" General Electric Co. Licensing Topical Report NEDO 24154 Vols. I and II and NEDE-24154 Vol. III as supplemented by letter dated September 5, 1980 from R.H. Buchholz (GE) to P. S. Check (NRC).

* Approved revision at time of plant operation.
** Approved revision number at time reload fuel analyses are performed.

4.5 SURVEILLANCE REQUIREMENTS BASES

The testing interval for the core and containment cooling systems is based on a quantitative reliability analysis, judgment, and practicality. The core cooling systems have not been designed to be fully testable during operation. For example, the core spray final admission valves do not open until reactor pressure has fallen to 350 psig. Thus, during operation, even if high drywell pressure were simulated, the final valves would not open. In the case of the HPCI, automatic initiation during power operation would result in pumping cold water into the reactor vessel which is not desirable.

The systems can be automatically actuated during a refueling outage and this will be done. To increase the availability of the individual components of the core and containment cooling systems, the components which make up the system, i.e., instrumentation, pumps, valve operators, etc., are tested more frequently. The instrumentation is functionally tested each month. Likewise the pumps and motor-operated valves are also tested each month to assure their operability. The combination of a yearly simulated automatic actuation test and monthly tests of the pumps and valve operators is deemed to be adequate testing of these systems.

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

The verification of the main steam relief valve operability during manual actuation surveillance testing must be made independent of temperatures indicated by thermocouples downstream of the relief valves. It has been found that a temperature increase may result with the valve still closed. This is due to steam being vented through the pilot valves during the surveillance test. By first opening a turbine bypass valve, and then observing its closure response during relief valve actuation, positive verification can be made for the relief valve opening and passing steam flow. Closure response of the turbine control valves during relief valve manual actuation would likewise serve as an adequate verification for the relief valve opening. This test method may be performed over a wide range of reactor pressures greater than 150 psig. Valve operation below 150 psig is limited by the spring tension exhibited by the relief valves.

The surveillance requirements to ensure that the discharge piping of the core spray, LPCI mode of the RHR, HPCI, and RCIC systems is filled provides for a visual observation that water flows from a high point vent. This ensures that the line is in a full condition.

Instrumentation has been provided on core spray and LPCI mode of RHR to monitor the pressure of water in the discharge piping between the monthly intervals at which the lines are vented and alarm the control room if the pressure is inadequate. This instrumentation will be calibrated on the same frequency as the safety system instrumentation and the alarm system tested monthly. This testing ensures that, during the interval between the monthly venting checks, the status of the discharge piping is monitored on a continuous basis. An alarm point of 40 psig for the low pressure of the fill system has been chosen because, due to elevations of piping within the plant, 39 psig is required to keep the lines full. The shutoff head of the fill system pumps is less than 90 psig and therefore will not defeat the low-pressure cooling pump discharge pressure interlock 100 psig as shown in Table 3.2-2. A margin of 10 psig is provided by the high pressure alarm point of 90 psig.

HPCI and RCIC systems normally take a suction from the Contaminated Condensate Storage Tanks (CCST's). The level in the CCST's is maintained at or above 9.5 feet. This level corresponds to an elevation which is greater than the elevation of the last check valves in the discharge pipes of either the HPCI or RCIC systems. Therefore, filled discharge piping of HPCI or RCIC systems is ensured when lined up to the CCST and tank level is at or above 9.5 feet.

The watertight bulkhead and submarine doors and the penetration seals for pipes and cables penetrating the vault walls and ceilings have been designed to withstand the maximum flood conditions. To assure that their installation is adequate for maximum flood conditions, a method of testing each seal has been devised.

In order to test an electrical penetration or pipe seal, compressed air is supplied to a test connection and the space between the fittings is pressurized to approximately 15 psig. The outer faces are then tested for leaks using a soap bubble solution.

In order to test the submarine doors, a test frame must be installed around each door. The frame is then pumped to a pressure of approximately 15 psig and held to test for leaktightness. The watertight bulkhead doors are tested by pressurizing the volume between the double-gasket seals to approximately 15 psig. The gasket seal area is inspected using a soap bubble solution. Each RHR service water vault contains a sump, which will collect any floor or equipment leakage inside the vault. A sump pump will automatically start on high level in the sump, and will pump the water out of the vault, via 2 discharge check valves outside the vault to the service water discharge pipe. A composite sampler is located on the sump discharge line. A radiation monitor is also located on the service water discharge. The sump discharge water is not expected to be contaminated, and any in-leakage to the vault is prevented by 2 check valves. Surveillance of these check valves is performed each operating cycle to assure their integrity. The previously installed bedplate drains to the turbine building equipment drain sump have been capped off permanently.

A level switch set at a water level of 6 inches is located inside each vault. Upon actuation, the switch alarms in the control room to notify the operator of trouble in the vault. The operator will also be aware of problems in the vaults/condensate pump room if the high-level alarm on the equipment drain sump is not terminated in a reasonable amount of time.

A system of level switches has been installed in the condenser pit to indicate and control flooding of the condenser area. The following switches are installed:

	Level	Function
a.	1 foot (one switch)	alarm, low water level
b.	3 feet (one switch)	alarm, high water level
c.	5 feet (two redundant switch pairs)	alarm and circulating water pump trip

Level (a) indicates water in the condenser pit from either the hotwell or the circulating water system. Level (b) is above the hotwell capacity and indicates a probable circulating water failure.

Should the switches at levels (a) and (b) fail or the operator fails to trip the circulating water pumps on alarm at level (b), the actuation of either level switch pair at level (c) shall trip the circulating water pumps automatically and alarm in the control room. These redundant level switch pairs at level (c) are designed and installed to IEEE 279, "Criteria for Nuclear Power Plant Protection Systems." As the circulating water pumps are tripped, either manually or automatically at level (c) of 5 feet, the maximum water level reached in the condenser pit due to pumping will be at elevation 568 feet 6 inches elevation (10 feet above condenser pit floor elevation 558 feet 6 inches; 5 feet plus an additional 5 feet attributed to pump coastdown).

In order to prevent the RHR service water pump motors and diesel generator cooling water pump motors from overheating a vault cooler is supplied for each pump. Each vault cooler is designed to maintain the vault at a maximum 105°F temperature during operation of its respective pump. For example, if diesel generator cooling water pump 1/2-3903 starts, its cooler also starts and maintains the vault at 105°F by removing heat supplied to the vault by the motor of pump 1/2-3903. If, at the same time that pump 1/2-3903 is in operation, RHR service water pump 1C starts, its cooler will also start and compensate for the added heat supplied to the vault by the 1C pump motor keeping the vault at 105°F.

Each of the coolers is supplied with cooling water from its respective pump's discharge line. After the water has been passed through the cooler it returns to its respective pump's suction line. The cooling water quantity needed for each cooler is approximately 1% to 5% of the design flow of the pumps so that the recirculation of this small amount of heated water will not affect pump or cooler operation.

Operation of the fans and coolers is required during shutdown and thus additional surveillance is not required.

Verification that access doors to each vault are closed following entrance by personnel is covered by station operating procedures.

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

Average Planar LHGR

At core thermal power levels less than or equal to 25%, operating plant experience and thermal hydraulic analyses indicate that the resulting average planar LHGR is below the maximum average planar LHGR by a considerable margin; therefore, evaluation of the average planar LHGR below this power level is not necessary. The daily requirement for calculating average planar LHGR above 25% rated thermal power is sufficient, since power distribution shifts are slow when there have not been significant power or control rod changes.

Local LHGR

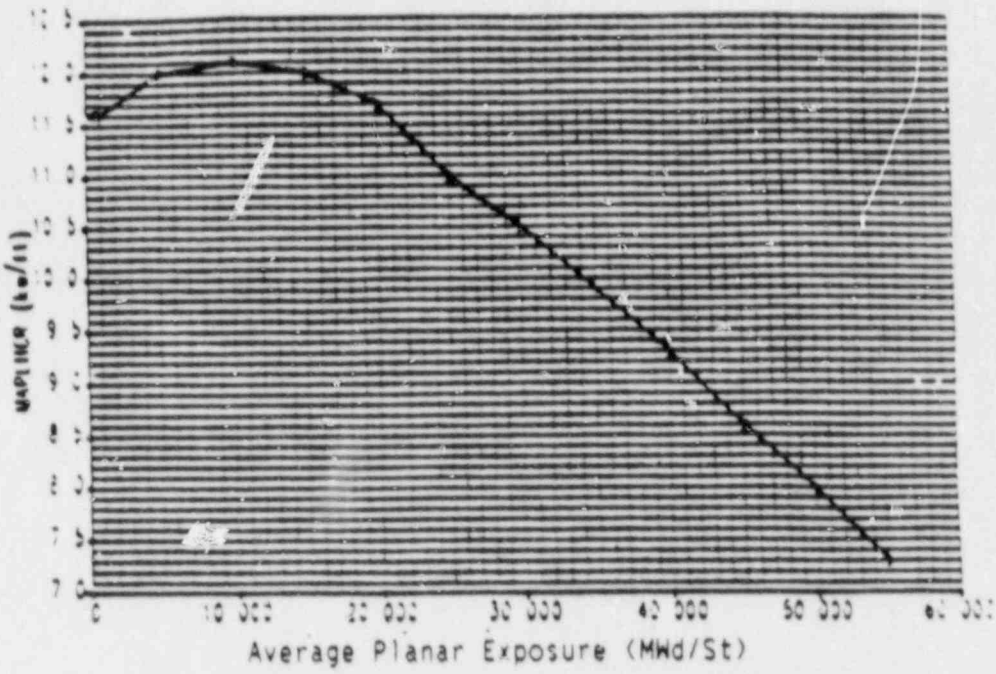
The LHGR as a function of core height shall be checked daily during reactor operation at greater than or equal to 25% power to determine if fuel burnup or control rod movement has caused changes in power distribution. A limiting LHGR value is precluded by considerable margin when employing any permissible control rod pattern below 25% rated thermal power.

Minimum Critical Power Ratio (MCPR)

At core thermal power levels less than or equal to 25%, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience and thermal hydraulic analysis indicate that the resulting MCPR value is in excess of requirements by a considerable margin. With this low void content, any inadvertent core flow increase would only place operation in a more conservative mode relative to MCPR.

The daily requirement for calculating MCPR above 25% rated thermal power is sufficient, since power distribution shifts are very slow when there have not been significant power or control rod changes. In addition, the K_f correction applied to the LCO provides margin for flow increases from low flows.

MAPLHGR Vs. Average Planar Exposure
Fuel Type Barrier LTA



MAPLHGR Vs. Average Planar Exposure
Fuel Types P8DRB265L/P8DGB265L

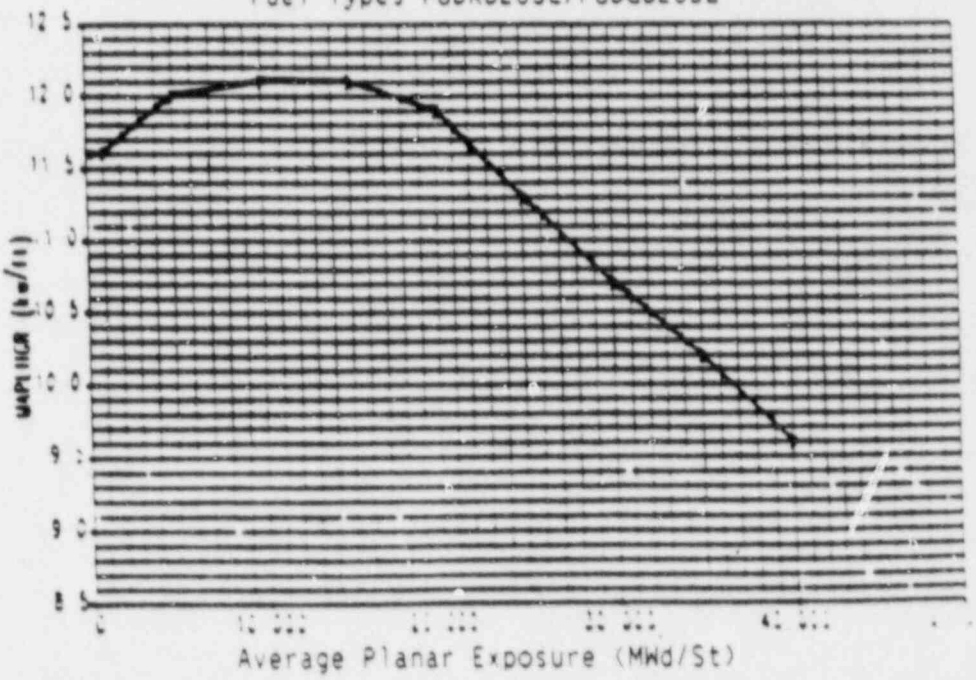
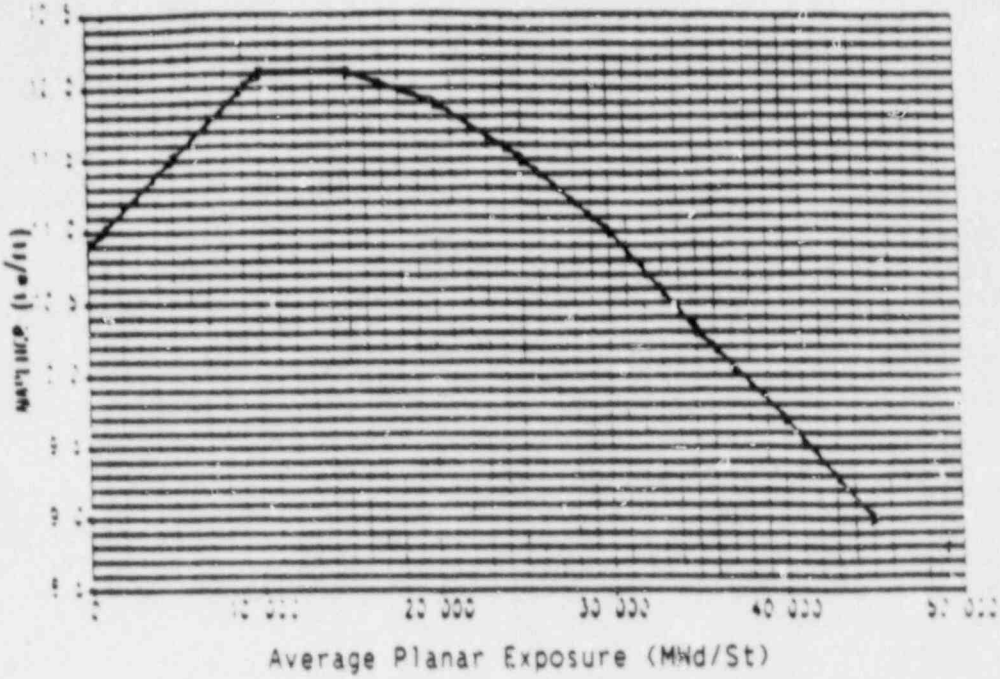


Figure 3.5-1 (Sheet 1 of 5)

MAPLHGR Vs. Average Planar Exposure
Fuel Type BP8DRB299



MAPLHGR Vs. Average Planar Exposure
Fuel Type P8DRB282

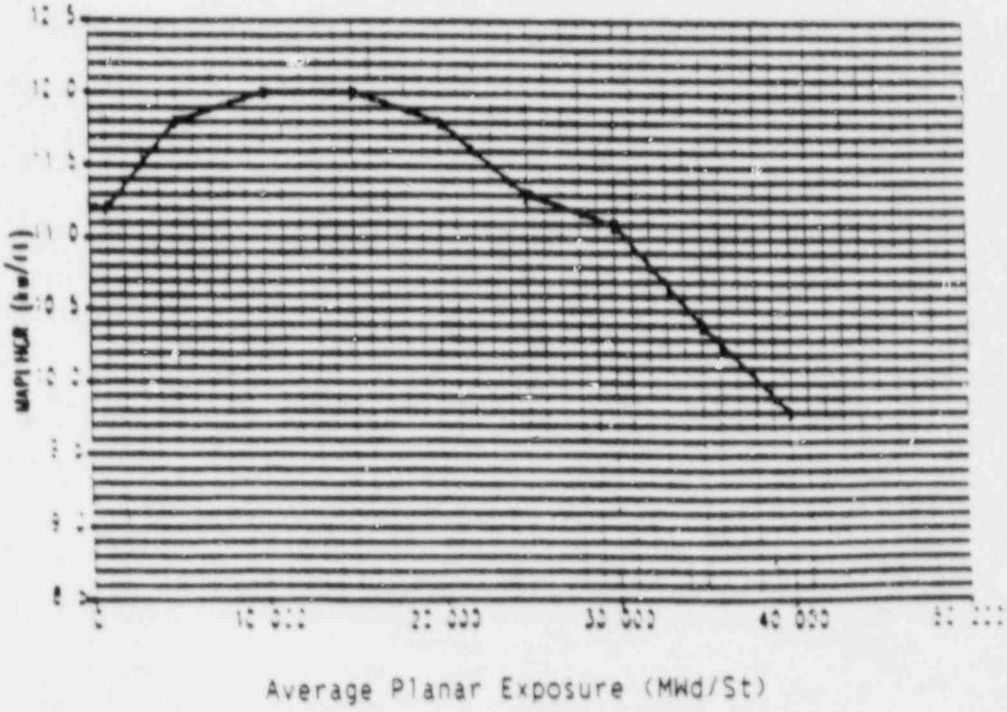
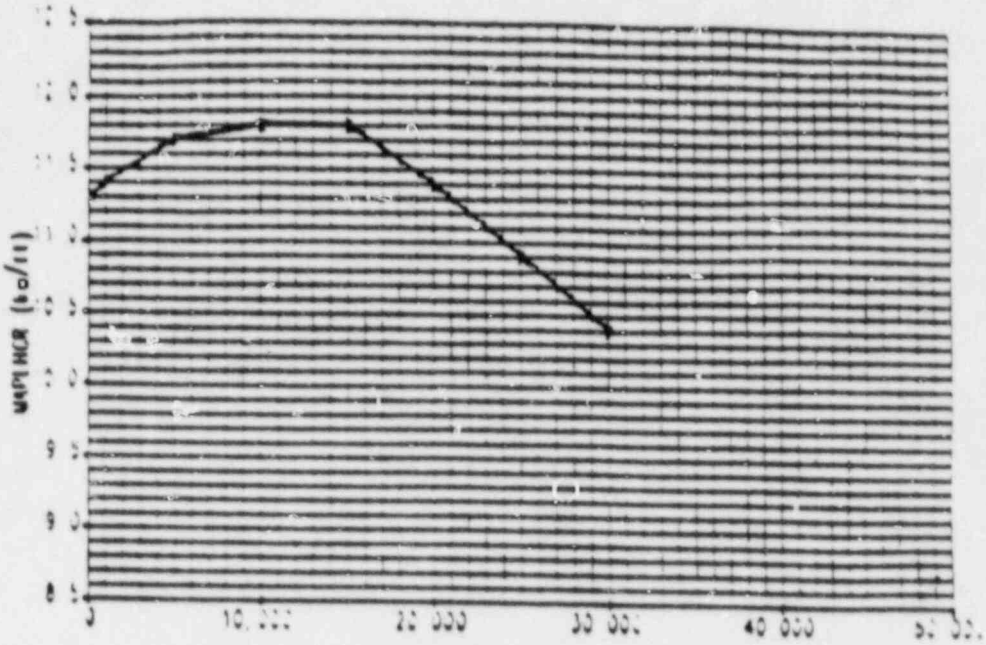


Figure 3.5-1 (Sheet 2 of 5)

MAPLHGR Vs. Average Planar Exposure
Fuel Type P8DRB239



MAPLHGR Vs. Average Planar Exposure
Fuel Types P8DRB265H/BP8DRB265H

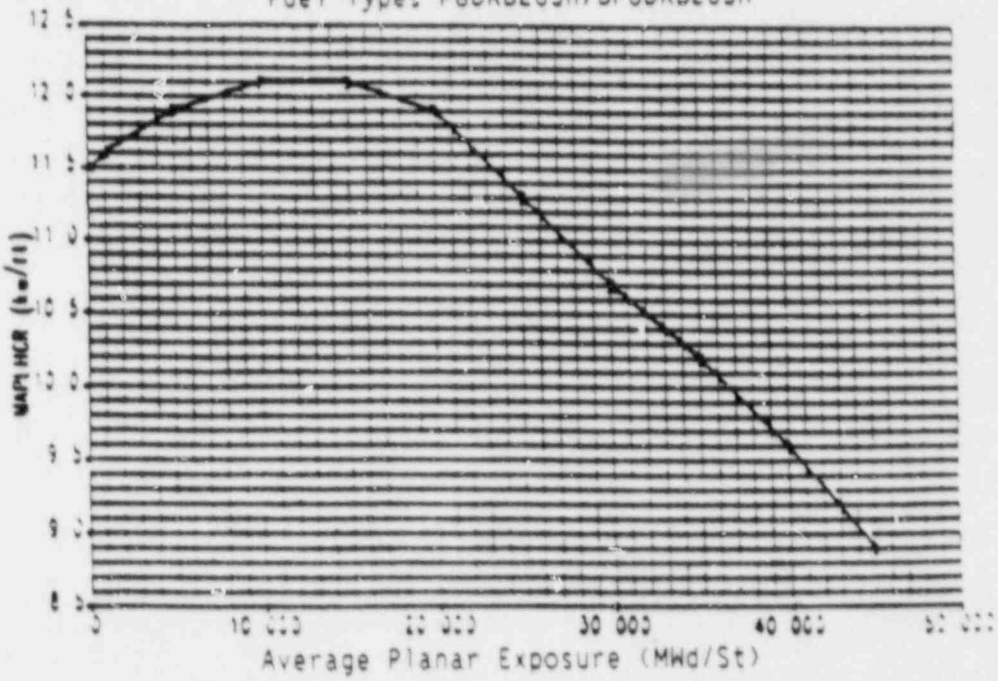
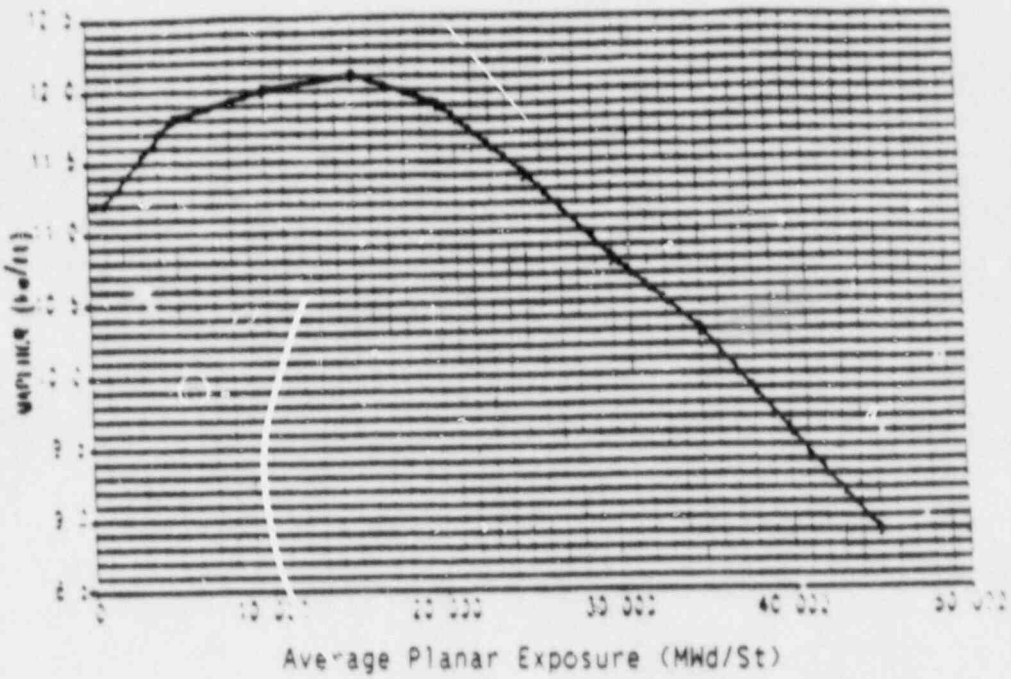


Figure 3.5-1 (Sheet 3 of 5)

MAPLHGR Vs. Average Planar Exposure
Fuel Type BP8DRB282



MAPLHGR Vs. Average Planar Exposure
Fuel Type BP8DRB283H

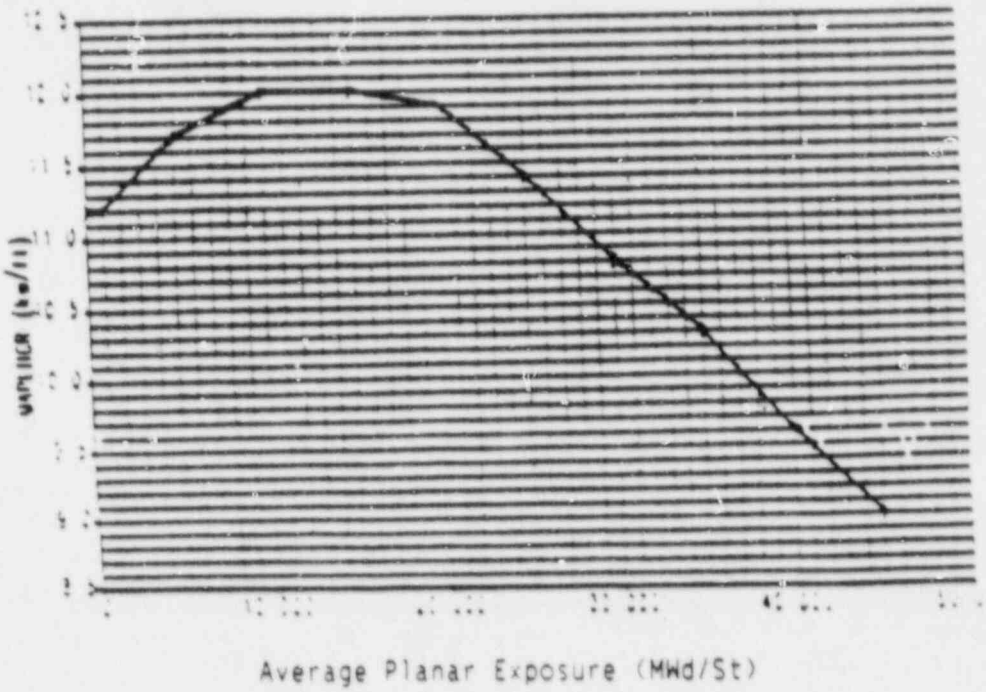
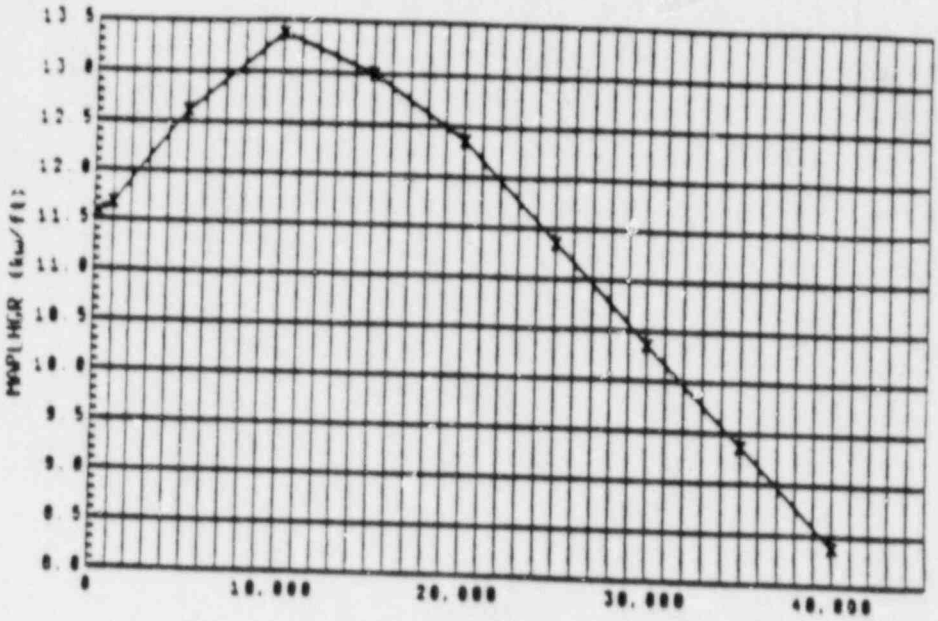


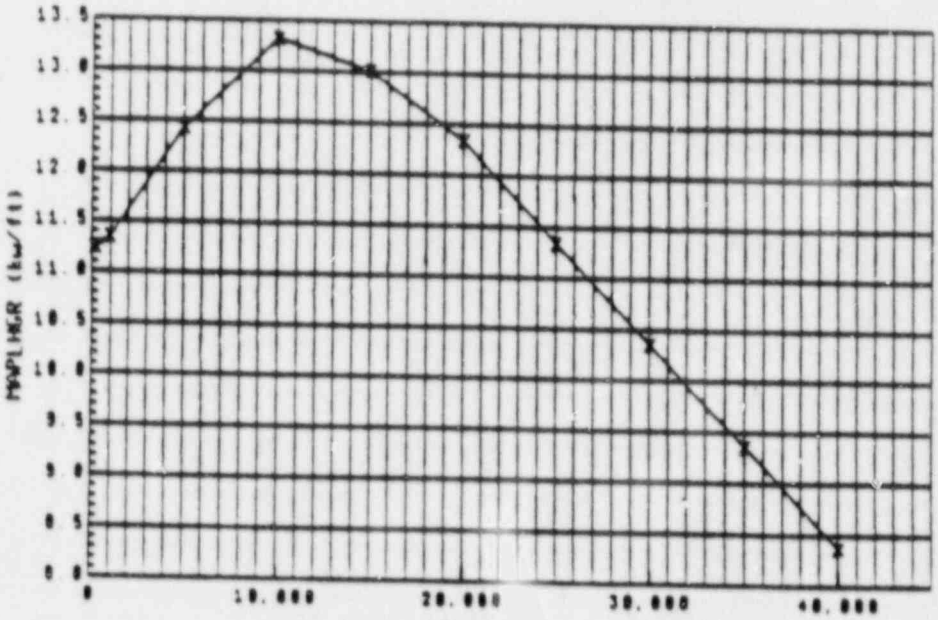
Figure 3.5-1 (Sheet 4 of 5)

MAPLHGR Vs. Average Planar Exposure
Fuel Type BD300A



Average Planar Exposure (MWd/St)

MAPLHGR Vs. Average Planar Exposure
Fuel Type BD300B



Average Planar Exposure (MWd/St)

Figure 3.5-1 (Sheet 5 of 5)

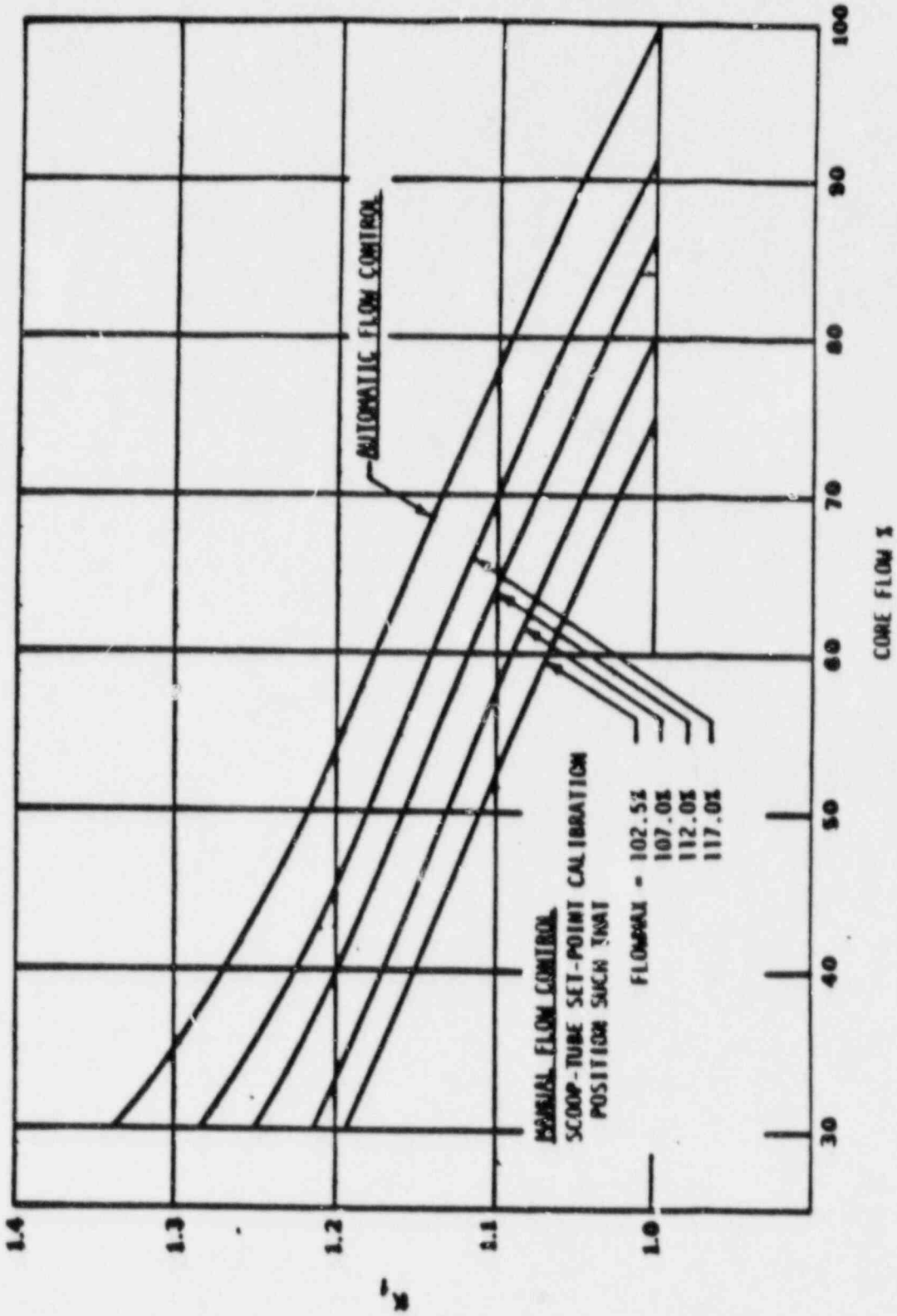


FIGURE 3.5-2
K_f FACTOR
3.5/4.5-29

3.6/4.6 PRIMARY SYSTEM BOUNDARY

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to the operating status of the reactor coolant system.

Objective:

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

SURVEILLANCE REQUIREMENTS

Applicability:

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

Objective:

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

SPECIFICATIONS

A. Thermal Limitations

1. Except as indicated in Specification 3.6.A.2 below, the average rate of reactor coolant temperature change during normal heatup or cooldown shall not exceed 100° F/hr when averaged over a 1-hour period.

2. A step reduction in reactor coolant temperature of 240°F is permissible so long as the limit in Specification 3.6.A.3 below is met.

3. At all times, the shell flange to shell temperature differential shall not exceed 140°F.

A. Thermal Limitations

1. During heatups and cooldowns the following temperatures shall be permanently recorded at 15-minute intervals:

   a. reactor vessel shell,

   b. reactor vessel shell flange, and

   c. recirculation loops A and B.

2. The temperatures listed in Specification 4.6.A.1 shall be permanently recorded subsequent to a heatup or cooldown at 15-minute intervals until three consecutive readings at each given location are within 5 degrees of each other.

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

B. Pressurization Temperature

1. The reactor vessel shall be vented and power operation shall not be conducted unless the reactor vessel temperature is equal to or greater than that shown in Figure 3.6-1. Operation for hydrostatic or leakage tests, during heatup or cooldown, and with the core critical shall be conducted only when vessel temperature is equal to or above that shown in the appropriate curve of Figure 3.6-1. Figure 3.6-1 is effective through 6 EFPY. At least six months prior to 6 EFPY new curves will be submitted.

2. The reactor vessel head bolting studs shall not be under tension unless the temperature of the vessel shell immediately below the vessel flange is ≥ 100°F.

B. Pressurization Temperature

1. Reactor vessel shell temperature and reactor coolant pressure shall be permanently recorded at 15-minute intervals whenever the shell temperature is below 220°F and the reactor vessel is not vented.

2. Neutron flux monitors and samples shall be installed in the reactor vessel adjacent to the vessel wall at the core midplane level. The monitor and sample program shall conform to ASTM E 185-66. The monitors and samples shall be removed and tested in accordance with the guidelines set forth in 10CFR50 Appendix H to experimentally verify the calculated values of integrated neutron flux that are used to determine the NDTT for Figure 3.6-1.

3. When the reactor vessel head bolting studs are tightened or loosened, the reactor vessel shell temperature immediately below the head flange shall be permanently recorded.

C. Coolant Chemistry

1. The steady-state radioiodine concentration in the reactor coolant shall not exceed 5 μCi of I-131 dose equivalent per gram of water.

C. Coolant Chemistry

1. a. A sample of reactor coolant shall be taken at least every 96 hours and analyzed for radioactive iodines of I-131 through I-135 during power operation. In addition, when chimney monitors indicate an increase in radioactive gaseous effluents of 25% or 5000 μCi/sec. whichever is greater, during steady-state reactor operation, a reactor coolant sample shall be taken and analyzed for radioactive iodines.

   b. An isotopic analysis of a reactor coolant sample shall be made at least once per month.

   c. Whenever the steady-state radioiodine concentration of prior operation is greater than 1% but less than 10% of Specification 3.6.C.1, a sample of reactor coolant shall be taken within 24 hours of any reactor startup and analyzed for radioactive iodines of I-131 through I-135.

d. Whenever the steady-state radioiodine concentration is greater than 10% of Specification 3.6.C.1, a sample of reactor coolant shall be taken prior to any reactor startup and analyzed for radioactive iodines of I-131 through I-135 as well as the coolant sample and analyses required by Specification 4.6.C.1.c above.

2. The reactor coolant water shall not exceed the following limits with steaming rates less than 100,000 lb/hr except as specified in Specification 3.6.C.3:

   conductivity 2 μmho/cm

   chloride ion 0.1 ppm

2. During startups and at steaming rates below 100,000 lb/hr, a sample of reactor coolant shall be taken every 4 hours and analyzed for conductivity and chloride content.

3. For reactor startups, the maximum value for conductivity shall not exceed 10 μmho/cm, and the maximum value for chloride ion concentration shall not exceed 0.1 ppm for the first 24 hours after placing the reactor in the power operating condition.

3. a. With steaming rates greater than or equal to 100,000 lb/hr, a reactor coolant sample shall be taken at least every 96 hours and when the continuous conductivity monitors indicate abnormal conductivity (other than short-term spikes) and analyzed for conductivity and chloride ion content.

   b. When the continuous conductivity monitor is inoperable, a reactor coolant sample should be taken at least daily and analyzed for conductivity and chloride ion content.

4. Except as specified in Specification 3.6.C.3 above, the reactor coolant water shall not exceed the following limits with steaming rates greater than or equal to 100,000 lb/hr:

   conductivity 10 μmho/cm

   chloride ion 1.0 ppm

5. If Specification 3.6.C.1, 3.6.C.2, 3.6.C.3, or 3.6.C.4 is not met, an orderly shutdown shall be initiated.

D. Coolant Leakage

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

2. Both the sump and air sampling systems shall be operable during reactor power operation. From and after the date that one of these systems is made or found to be inoperable for any reason, reactor power operation is permissible only during the succeeding 7 days.

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

D. Coolant Leakage

Reactor coolant system leakage shall be checked by the sump and air sampling system. Sump flow monitoring and recording shall be performed once per shift. Air sampling shall be performed once per day.

E. Safety and Relief Valves

1. Prior to reactor startup for power operation, during reactor power operating conditions, and whenever the reactor coolant pressure is greater than 90 psig and temperature greater than 320°F, all nine of the safety valves shall be operable. The solenoid-activated pressure valves shall be operable as required by Specification 3.5.D.

2. If Specification 3.6.E.1 is not met, the reactor shall remain shut down until the condition is corrected or, if in operation, an orderly shutdown shall be initiated and the reactor coolant pressure and temperature shall be below 90 psig and 320°F within 24 hours.

E. Safety and Relief Valves

A minimum of 1/2 of all safety valves shall be bench checked or replaced with a bench checked valve each refueling outage. The popping point of the safety valves shall be set as follows:

Number of Valves	Setpoint (psig)
1	1135[1]
2	1240
2	1250
4	1260

The allowable setpoint error for each valve is ±1%.

All relief valves shall be checked for set pressure each refueling outage. The set pressures shall be:

Number of Valves	Setpoint (psig)
1	≤1135[1]
2	≤1115
2	≤1135

[1] Target Rock combination safety/relief valve.

F. Structural Integrity

The structural integrity of the primary system boundary shall be maintained at the level required by the ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components", 1974 Edition, Summer 1975 Addenda (ASME Code Section XI).

F. Structural Integrity

The nondestructive inspections listed in Table 4.6-1 shall be performed as specified in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1971 Edition, Summer 1971 Addenda. The results obtained from compliance with this specification will be evaluated after 5 years and the conclusions will be reviewed with the NRC.

Components of the primary system boundary whose inservice examination reveals the absence of flaw indications or flaw indications not in excess of the allowable indication standards of this Code are acceptable for continued service. Plant operation with components which have in-service examination flaw indication(s) in excess of the allowable indication standards of the Code shall be subject to NRC approval.

a. Components whose inservice examination reveals flaw indication(s) in excess of the allowable indication standards of the ASME Code, Section XI, are unacceptable for continued service unless the following requirements are met:

   1) An analysis and evaluation of the detected flaw indication(s) shall be submitted to the NRC that demonstrate that the component structural integrity justifies continued service. The analysis and evaluation shall follow the procedures outlined in Appendix A, "Evaluation of Flaw Indications", of ASME Code, Section XI.

   2) Prior to the resumption of service, the NRC shall review the analysis and evaluation and either approve resumption of plant operation with the affected component or require that the component be repaired or replaced.

b. For components approved for continued service in accordance with paragraph a. above, reexamination of the area containing the flaw indication(s) shall be conducted during each scheduled successive inservice inspection. An analysis and evaluation shall be submitted to the NRC following each inservice inspection. The analysis and evaluation shall follow the procedures outlined in Appendix A, "Evaluation of Flaw Indications", of ASME Code, Section XI, and shall reference prior analyses submitted to the NRC to the extent applicable. Prior to resumption of service following each inservice inspection, the NRC shall review the analysis and evaluation and either approve resumption of plant operation with the affected component or require that the component be repaired or replaced.

c. Repair or replacement of components, including reexaminations, shall conform with the requirements of the ASME Code, Section XI. In the case of repairs, flaws shall be either removed or repaired to the extent necessary to meet the allowable indication standards specified in ASME Code, Section XI.

G. Jet Pumps

1. Whenever the reactor is in the Startup/Hot Standby or Run modes, all jet pumps shall be intact, and all operating jet pumps shall be operable. If it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 24 hours.

2. Flow indication from each of the 20 jet pumps shall be verified prior to initiation of reactor startup from a cold shutdown condition.

G. Jet Pumps

1. Whenever there is recirculation flow with the reactor in the Startup/Hot Standby or Run modes, jet pump integrity and operability shall be checked daily by verifying that the following two conditions do not occur simultaneously:

   a. The recirculation pump flow differs by more than 10% from the established speed-flow characteristics.

   b. The indicated total core flow is more than 10% greater than the core flow value derived from established core plate DP-core flow relationships.

2. Additionally, when operating with one recirculation pump with the equalizer valves closed, the diffuser to lower plenum differential pressure shall be checked daily, and the differential pressure of any jet pump in the idle loop shall not vary by more than 10% from established patterns.

3. The indicated core flow is the sum of the flow indication from each of the 20 jet pumps. If flow indication failure occurs for two or more jet pumps, immediate corrective action shall be taken. If flow indication for all but one jet pump cannot be obtained within 12 hours, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 24 hours.

3. The baseline data required to evaluate the conditions in Specifications 4.6.G.1 and 4.6.G.2 will be acquired each operating cycle.

H. Recirculation Pump Flow Limitations

1. Whenever both recirculation pumps are in operation, pump speeds shall be maintained within 10% of each other when power level is greater than 80% and within 15% of each other when power level is less than 80%.

H. Recirculation Pump Flow Limitations

Recirculation pumps speed shall be checked daily for mismatch.

2. If Specification 3.6.H.1 cannot be met, one recirculation pump shall be tripped.

3. During Single Loop Operation for more than 12 hours, the following restrictions are required:

   a. The MCPR Safety Limit shall be increased by 0.01 (T.S. 1.1A);

   b. The MCPR Operating Limit shall be increased by 0.01 (T.S. 3.5.K);

   c. The flow biased APRM Scram and Rod Block Setpoints shall be reduced by 3.5% to read as follows:

      T.S. 2.1.A.1;
      $S \leq .58WD + 58.5$

      T.S. 2.1.A.1;*
      $S \leq (.58WD + 58.5)$ FRP/MFLPD

      T.S. 2.1.B;
      $S \leq .58WD + 46.5$

      T.S. 2.1.B;*
      $S \leq (.58WD + 46.5)$ FRP/MFLPD

      T.S. 3.2.C (Table 3.2-3);*
      APRM Upscale $\leq (.58WD + 46.5)$ FRP/MFLPD

      * In the event that MFLPD exceeds FRP.

   d. The flow biased RBM Rod Block setpoints shall be reduced by 4.0% to read as follows:

      T.S. 3.2.C (Table 3.2-3);
      RBM Upscale $\leq .65WD + 39$

   e. The suction valve in the idle loop shall be closed and electrically isolated except when the idle loop is being prepared for return to service.

I. Shock Suppressors (Snubbers)

1. During all modes of operation except Shutdown and Refuel, all snubbers listed in Table 3.6-1 shall be operable except as noted in 3.6.I.2 following.

I. Shock Suppressors (Snubbers)

The following surveillance requirements apply to all snubbers listed in Table 3.6-1.

1. Visual inspections shall be performed in accordance with the following schedule utilizing the acceptance criteria given by Specification 4.6.I.2.

Number of Snubbers Found Inoperable During Inspection or During Inspection Interval	Next Required Inspection Interval
0	18 months ±25%
1	12 months ±25%
2	6 months ±25%
3,4	124 days ±25%
5,6,7	62 days ±25%
≥8	31 days ±25%

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

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.

Snubber service life monitoring shall be followed by the snubber surveillance inspection records and maintenance history records. The above record retention method shall be used to prevent the snubbers from exceeding a service life.

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

2. Visual inspections shall verify:

   a. There are no visible indications of damage or impaired operability, and

   b. Attachments to the foundation or supporting structure are secure.

   c. For hydraulic snubbers, the hydraulic fluid resorvoir and fluid connections shall be inspected for operability.

3. If the requirements of 3.6.I.1 and 3.6.I.2 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 36 hours.

3. Once each refueling cycle a representative sample of 10% of the total of each type of snubber in use in the plant shall be functionally tested either in place or in a bench test. For each snubber that does not meet the functional test criteria, an additional 10% of that type of snubber shall be functionally tested.

4. If a snubber is determined to be inoperable while the reactor is in the Shutdown or Refuel mode, the snubber shall be made operable prior to reactor startup.

4. The hydraulic snubbers shall be tested for:

   a. operability, including verification of proper piston movement, lockup, and bleed. When competitive marketable test fixtures are available, but no later than 12/31/83, the functional test shall include demonstrating snubber bleed, or release, rate is within the specified range in compression or tension.

b. When competitive marketable test fixtures are available, but no later than 12/31/83, the functional test shall also demonstrate that activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

5. Snubbers may be added to safety-related systems without prior license Amendment to Table 3.6-1 provided that a revision to Table 3.6-1 is included with the next license amendment request.

5. The mechanical snubber functional tests shall verify:

a. That the breakaway force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum force.

b. That the activation (restraining action) is achieved within the specified range of acceleration in both tension and compression. This test cannot be performed until competitive marketable test fixtures are manufactured and on site. Until such test fixtures are available, but no later than 12/31/83, the functional test for mechanical snubbers will be limited to 4.6.I.5.a.

6. When a snubber is deemed inoperable, a review shall be conducted to determine the mode of failure and to decide if an engineering evaluation should be performed. If the engineering evaluation is deemed necessary, it will determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

7. If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if determined to be generically deficient all snubbers of the same design, subject to the same defect shall be functionally tested.

8. In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber (if it is repaired and installed in another position) and the spare snubber shall be retested. Test results of these snubbers may not be included for the resampling.

3.6 LIMITING CONDITIONS FOR OPERATION BASES

A. Thermal Limitations

The reactor vessel design specification requires that the reactor vessel be designed for a maximum heatup and cooldown rate of the contained fluid (water) of 100°F/hour averaged over a period of 1 hour. This rate has been chosen based on past experience with operating power plants. The associated time periods for heatup and cooldown cycles when the 100°F/hr rate is limiting provides for efficient but safe plant operation.

The reactor vessel manufacturer has designed the vessel to the above temperature criterion. In the course of completing the design, the manufacturer performed a detailed stress analysis. This analysis includes more severe thermal conditions than those which would be encountered during normal heating and cooling operations.

Specific analyses were made based on a heating and cooling rate of 100°F/hr applied continuously over a temperature range of 100°F to 550°F. Because of the slow temperature-time response of the massive flanges relative to the adjacent head and shell sections, calculated temperatures obtained were 500°F (shell) and 360°F (flange) (140°F differential).

Both axial and radial thermal stresses were considered to act concurrently with full primary loadings. Calculated stresses were within ASME Boiler and Pressure Vessel Code Section III stress intensity and fatigue limits even at the flange area where maximum stress occurs.

The flange metal temperature differential of 140°F occurred as a result of sluggish temperature response and the fact that the heating rate continued over a 450°F coolant temperature range.

The uncontrolled cooldown rate of 240°F/hr was based on the maximum expected transient over the lifetime of the reactor vessel. This maximum expected transient is the injection of cold water into the vessel by the high-pressure coolant injection subsystem. This transient was considered in the design of the pressure vessel, and ten such cycles were considered in the design. Detailed stress analyses were conducted to assure that the injection of cold water into the vessel by the HPCI would not exceed ASME stress code limitations.

B. Pressurization Temperature

The reactor coolant system 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. These restrictions on inservice hydrostatic testing, on heatup and cooldown, and on

critical core operation shown in Figure 3.6-1, were established to be in conformance with Appendix G to 10CFR50.

In evaluating the adequacy of ferritic steels Sa302B it is necessary that the following be established:

1. The reference nil-ductility temperature (RT_{NDT}) for all vessel and adjoining materials.

2. The relationship between RT_{NDT} and integrated neutron flux (fluence, at energies > Mev), and

3. The fluence at the location of a postulated flaw.

The initial RT_{NDT} of the main closure flange, the shell and head materials connecting to these flanges, and connecting welds is 10°F. However, the vertical electroslag welds which terminate immediately below the vessel flange have an RT_{NDT} of 40°F. Reference Appendix F to the Dresden FSAR. The closure flanges and connecting shell materials are not subject to any appreciable neutron radiation exposure, nor are the vertical electroslag seams. The flange area is moderately stressed by tensioning the head bolts. Therefore, as is indicated in curves (a) and (b) of Figure 3.6-1, the minimum temperature of the vessel shell immediately below the vessel flange is established as 100°F below a pressure of 400 psig. (40°F + 60°F, where 40°F is the RT_{NDT} of the electroslag weld and 60°F is a conservatism required by the ASME Code). Above approximately 400 psig pressure, the stresses associated with pressurization are more limiting than the bolting stresses, a fact that is reflected in the non-linear portion of curves (a) and (b). Curve (c), which defines the temperature limitations for critical core operation, was established per Section IV 2.c. of Appendix G of 10CFR50. Each of the curves, (a), (b) and (c) define temperature limitations for unirradiated ferritic steels. Provision has been made for the modification of these curves to account for the change in RT_{NDT} as a result of neutron embrittlement.

The withdrawal schedule in Table 4.6-2 is based on the three capsule surveillance program as defined in Section II.C.3.a. of 10 CFR 50 Appendix H. The accelerated capsule (Near Core Top Guide) are not required by Appendix H but will be tested to provide additional information on the vessel material.

This surveillance program conforms to ASTM E 185-73 "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels" with one exception. The base metal specimens of the vessel were [illegible]e with their longitudinal axes parallel to the principle rolling direction of the vessel plate.

C. Coolant Chemistry

A steady-state radioiodine concentration limit of 5 µCi of I-131 dose equivalent per gram of water in the reactor coolant system can be reached if the gross radioactivity in the gaseous effluents are near the limit as set forth in Specification 3.8.C.1 or there is a failure or prolonged shutdown of the cleanup demineralizer. In the event of a steamline rupture outside the drywell, the NRC staff calculations show the resultant radiological dose at the site boundary to be less than 30 rem to the thyroid. This dose was calculated on the basis of the radioiodine concentration limit of 5 µCi of I-131 dose equivalent per gram of water, atmospheric diffusion from an elevated release at 30 meters under fumigation conditions for Pasquill Type F, 1 meter per second wind speed, and a steamline isolation valve closure time of 5 seconds.

NRC staff calculations show that an instrument line break which released about 100,000 pounds of coolant would yield a calculated dose at the site boundary of about 110 rem to the thyroid on the conservative basis that all of the radioiodine contained in the 100,000 pounds of coolant is released at ground level. However, there is reasonable assurance that the reactor building integrity would be maintained for this event and the standby gas treatment would function so as to reduce the calculated thyroid dose by a factor of approximately 2.

The reactor coolant sample will be used to assure that the limit of Specification 3.6.C.1 is not exceeded. The radioiodine concentration would not be expected to change rapidly during steady-state operation over a period of 96 hours. In addition, the trend of the radioactive gaseous effluents, which is continuously monitored, is a good indicator of the trend of the radioiodine concentration in the reactor coolant. When a significant increase in radioactive gaseous effluents is indicated, as specified, an additional reactor coolant sample shall be taken and analyzed for radioactive iodine.

Whenever an isotopic analysis is performed, a reasonable effort will be made to determine a significant percentage of those contributors representing the total radioactivity in the reactor coolant sample. Usually, at least 80% of the total gamma radioactivity can be identified by the isotopic analysis.

It has been observed that radioiodine concentration can change rapidly in the reactor coolant during transient reactor operations such as reactor shutdown, reactor power changes, and reactor startup if failed fuel is present. As specified, additional reactor coolant samples shall be taken and analyzed for reactor operations in which steady-state radioiodine concentrations in the reactor coolant indicate various levels of iodine releases from the fuel. Since the radioiodine concentration in the reactor coolant is not

continuously measured, reactor coolant sampling would be ineffective as a means to rapidly detect gross fuel element failures. However, some capability to detect gross fuel element failures is inherent in the radiation monitors in the off-gas system and on the main steamline.

Materials in the primary system are primarily 304 stainless steel and the Zircaloy fuel cladding. The reactor water chemistry limits are established to prevent damage to these materials. Limits are placed on chloride concentration and conductivity. The most important limit is that placed on chloride concentration to prevent stress corrosion cracking of the stainless steel. The attached graph, Figure 4.6-1, illustrates the results of tests on stressed 304 stainless steel specimens. Failures occurred at concentrations above the curve; no failures occurred at concentrations below the curve. According to the data, allowable chloride concentrations could be set several orders of magnitude above the established limit, at the oxygen concentration (0.2-0.3 ppm) experienced during power operation. Zircaloy does not exhibit similar stress corrosion failures.

However, there are various conditions under which the dissolved oxygen content of the reactor coolant water could be higher than 0.2-0.3 ppm, such as refueling, reactor startup and hot standby. During these periods with steaming rates less than 100,000 lb/hr, a more restrictive limit of 0.1 ppm has been established to assure that the chloride-oxygen combinations of Figure 4.6-1 are not exceeded. At steaming rates of at least 100,000 lb/hr, boiling occurs causing deaeration of the reactor water, thus maintaining oxygen concentration at low levels.

When conductivity is in its proper normal range, pH, chloride, and other impurities affecting conductivity must also be within their normal range. When and if conductivity becomes abnormal, then chloride measurements are made to determine whether or not they are also out of their normal operating values.

This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt, e.g., Na_2SO_4, which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are in fact high due to purposeful addition of additives. In the case of BWR's however, where no additives are used and where neutral pH is maintained, conductivity provides a very good measure of the quality of the reactor water. Significant changes therein provide the operator with a warning mechanism so he can investigate and remedy the condition causing the change before limiting conditions, with respect to variables affecting the boundaries of the reactor, are exceeded. Methods available to the operator for correcting the offstandard condition include operation of the reactor cleanup system, reducing the input of impurities, and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature-dependent corrosion rates and provide time for the cleanup

system to reestablish the purity of the reactor coolant. During startup periods, which are in the category of less than 100,000 lb/hr, conductivity may exceed 2 μmho/cm because of the initial evolution of gases and the initial addition of dissolved metals. During this period of time when the conductivity exceeds 2 μmho (other than short-term spikes), samples will be taken to assure the chloride concentration is less than 0.1 ppm.

The conductivity of the reactor coolant is continuously monitored. The samples of the coolant which are taken every 96 hours will serve as a reference for calibration of these monitors and are considered adequate to assure accurate readings of the monitors. If conductivity is within its normal range, chlorides and other impurities will also be within their normal ranges. The reactor coolant samples will also be used to determine the chlorides. Therefore, the sampling frequency is considered adequate to detect long-term changes in the chloride ion content. Isotopic analyses required by Specification 4.6.C.1.b may be performed by a gamma scan.

D. Coolant Leakage

Allowable leakage rates of coolant from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes and on the ability to make up coolant system leakage in the event of loss of offsite a-c power. The normally expected background leakage due to equipment design and the detection capability for determining coolant system leakage were also considered in establishing the limits. The behavior of cracks in piping systems has been experimentally and analytically investigated as part of the USAEC sponsored Reactor Primary Coolant System Rupture Study (the Pipe Rupture Study). Work utilizing the data obtained in this study indicates that the leakage from a crack can be detected before the crack grows to a dangerous or critical size by mechanically or thermally induced cyclic loading, 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 Specification 3.6.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 Specification 3.6.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 less than the magnitude specified can be detected reasonably in a matter of few hours utilizing the available leakage detection schemes, and if the origin cannot be determined in a reasonably short time, the plant should be shut down to allow further investigation and corrective action.

The capacity of the drywell sump is 100 gpm, and the capacity of the drywell equipment drain tank pumps is also 100 gpm.

Removal of 50 gpm from either of these sumps can be accomplished with considerable margin.

The performance of the reactor coolant leakage detection system will be evaluated during the first 2 years of station operation, and the conclusions of this evaluation will be reported to the NRC.

E. Safety and Relief Valves

Experience in safety valve operation shows that a testing of 50% of the safety valves per refueling outage is adequate to detect failure or deterioration. The tolerance value is specified in Section III of the ASME Boiler and Pressure Vessel Code as ± 1% of design pressure. An analysis has been performed which shows that with all safety valves set 1% higher, the reactor coolant pressure safety limit of 1375 psig is not exceeded. Solenoid-actuated relief valves are used to avoid activation of the safety valves. In view of the fact that the solenoid-activated relief valves are more complicated, it is prudent to test them at each refueling outage. The safety valves are required to be operable above the design pressure (90 psig) at which the core spray subsystems are not designed to deliver full flow.

F. Structural Integrity

A preservice inspection of the components listed in Table 4.6-1 will be conducted after site erection to assure the system is free of gross defects and as a reference base for later inspections.

Prior to operation, the reactor primary system will be free of gross defects. In addition, the facility has been designed such that gross defects should not occur throughout life. The inspection program given in Table 4.6-1 was based on Section XI of the ASME Boiler and Pressure Vessel Code, 1971 Edition, Summer 1971 Addenda, which was followed except where accessibility for inspection was not provided. This edition of the Code is suitable for detecting flaw indications but does not provide adequate guidance for the evaluation of ultrasonic reflectors. The requirement in the 1971 Edition of Section XI that the operator evaluate the reflector to determine the size, shape, and nature can best be satisfied by examination and evaluation of the flaw in accordance with the techniques presented in Appendix A to ASME Section XI in the 1974 Edition, Summer 1975 Addenda. It is the intent of this specification to require inservice inspection of the primary system boundary per Table 4.6-1 of this specification and the 1971 Edition of ASME Section XI including the Summer 1971 Addenda and to permit the evaluation of flaws in excess of the acceptance standards of that Edition and Addenda in accordance with the techniques of the 1974 version.

Table 4.6-1 was based on Section XI of the ASME Boiler and Pressure Vessel Code, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems, which was followed except where accessibility for inspection was not provided. The Commonwealth Edison Company recognizes the importance of inspection of those areas which are presently not accessible and will study and implement, if practicable, new means to include those areas within the inspection program. This inspection provides further assurance that gross defects are not occurring after the system is in service. This inspection will reveal problem areas should they occur before a leak develops.

The special inspection of the main feed and steamlines is to provide added protection against pipe whip, in addition to the protective energy absorbing system to be installed inside the drywell as described in Amendment 27 to the SAR. The Group I welds are selected on the basis of an analysis that shows these welds are the highest stress welds and that due to their physical location, a break would result in the least interference and maximum energy upon impact with the drywell. These welds are the only ones which offer any significant risk and are therefore inspected 4 times as often as the other welds within the drywell.

Group II welds are selected because without regard for the operating stress levels and interfering equipment, they have sufficient theoretical energy to penetrate and would propel the pipe toward the containment. They are therefore included in first inspection. Upon consideration of impact angle, interfering equipment, and the distance they travels, no substantial risk is involved and no extra inspection is needed.

In addition, extensive visual inspection for leaks will be made periodically on critical systems. The inspection program specified encompasses the major areas of the vessel and piping systems within the drywell. The inspection period is based on the observed rate of growth of defects from fatigue studies sponsored by the NRC. These studies show that it requires thousands of stress cycles at stresses beyond any expected to occur in a reactor system to propagate a crack. The test frequency established is at intervals such that in comparison to study results only a small number of stress cycles at values below limits will occur. On this basis, it is considered that the test frequencies are adequate.

The type of inspection planned for each component depends on location, accessibility, and type of expected defect. Direct visual examination is proposed wherever possible since it is sensitive, fact, and reliable. Magnetic particle and liquid penetrant inspections are planned where practical and where added sensitivity is required. Ultrasonic testing and radiography shall be used where defects can occur on concealed surfaces.

After 5 years of operation, a program for inservice inspection of piping and components within the primary pressure boundary which are outside the downstream containment isolation valve shall be submitted to the NRC.

G. Jet Pumps

Failure of a jet pump nozzle assembly holddown mechanism, nozzle assembly, and/or riser increases the cross-sectional flow area for blowdown following the postulated design-basis double-ended recirculation line break. Therefore, if a failure occurs, repairs must be made to assure the validity of the calculated consequences.

The following factors form the basis for the surveillance requirements:

1. A break in a jet pump decreases the flow resistance characteristic of the external piping loop causing the recirculation pump to operate at a higher flow condition when compared to previous operation.

2. The change in flow rate of the failed jet pump produces a change in the indicated flow rate of that pump relative to the other pumps in that loop. Comparison of the data with a normal relationship or pattern provides the indication necessary to detect a failed jet pump.

3. The jet pump flow deviation pattern derived from the diffuser to lower plenum differential pressure readings will be used to further evaluate jet pump operability in the event that the jet pumps fail the tests in Sections 4.6.G.1 and 2.

Agreement of indicated core flow with established core plate-core flow relationships provides the most assurance that recirculation flow is not bypassing the core through inactive or broken jet pumps. This bypass flow is reverse with respect to normal jet flow. The indicated total core flow is a summation of the flow indications for the 20 individual jet pumps. The total core flow measuring instrumentation sums reverse jet pump flow as though it were forward flow. Thus the indicated flow is higher than actual core flow by at least twice the normal flow through any backflowing pump. Reactivity inventory is known to a high degree of confidence so that even if a jet pump failure occurred during a shutdown period, subsequent power ascension would promptly demonstrate abnormal control rod withdrawal for any power-flow operating map point.

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

H. Recirculation Pump Flow Limitations

The LPCI loop selection logic is described in the SAR, Section 6.2.4.2.5. For some limited low probability accidents with the recirculation loop operating with large speed differences, it is possible for the logic to select the wrong loop for injection. For these limited conditions, the core spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, a procedural limitation has been placed on the allowable variation in speed between the recirculation pumps.

The licensee's analyses indicate that above 80% power the loop select logic could not be expected to function at a speed differential of 15%. Below 80% power, the loop select logic would not be expected to function at a speed differential of 20%. This specification provides a margin of 5% in pump speed differential before a problem could arise. If the reactor is operating on one pump, the loop select logic trips that pump before making the loop selection.

Analyses have been performed which support indefinite single loop operation provided the appropriate restrictions are implemented within 12 hours. The MCPR Safety Limit has been increased by 0.01 to account for core flow and TIP reading uncertainties which are used in the statistical analysis of the safety limit. The MCPR Operating Limit has also been increased by 0.01 to maintain the same margin to the safety limit as during Dual Loop operation.

The flow biased scram and rod block setpoints are reduced to account for uncertainties associated with backflow through the idle jet pumps when the operating recirculation pump is above 20-40% of rated speed. This assures that the flow biased trips and blocks occur at conservative neutron flux levels for a given core flow.

The closure of the suction valve in the idle loop prevents the loss of LPCI flow through the idle recirculation pump into the downcomer.

I. Snubbers

All snubbers are required OPERABLE to ensure that the structural integrity of the reactor coolant system and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on non-safety-related systems and then only if their failure or failure of the system on which they are installed, would have no adverse effect on any safety-related system.

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

Snubber service life monitoring will be followed by the existing snubber surveillance inspection records and maintenance history records. The above record retention method should be used to prevent the hydraulic snubber from exceeding a service life of 10 years and the mechanical snubbers from exceeding a service life of 40 years.

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, or are similarly located or exposed to the same environmental conditions such as temperature, radiation, and vibration.

To provide assurance of snubber functional reliability, a representative sample of the installed snubbers will be functionally tested during plant shutdowns at refueling cycle intervals. Hydraulic snubber functional testing will include stroking of the snubbers to verify piston movement, lockup and bleed. Functional testing of the mechanical snubber will consist of verification that the force that initiates free movement of the snubber in either tension or compression is less than the maximum breakaway friction force. The remaining portions of the functional test consisting of verification that the activation (restraining action) is achieved within the specified range of acceleration in both tension and compression will not be done. This is due to the lack of competitive marketable test equipment available for Station use.

When a snubber is found inoperable, a review shall be performed to determine the snubber mode of failure. Results of the review shall be used to determine if an engineering evaluation of the safety-related system or component is necessary. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the support component or system.

Observed failures of these sample snubbers shall require functional testing of additional units.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance programs.

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
M	1-1	Drywell; core spray return line 1-1403-10"	644	X		X	
M	1-2	Drywell; core spray return line 1-1403-10"	644	X		X	
M	1-3	Drywell; core spray return line 1-1404-10"	642	X		X	
M	1-4	Drywell; core spray return line 1-1404-10"	642	X		X	
M	1-5	Drywell; RHR return line 1-1012A-16"	603	X		X	
M	1-6	Drywell; RHR return line 1-1012A-16"	599	X		X	
M	1-7	Drywell; RHR return line 1-1012B-16"	598	X		X	
M	1-8	Drywell; RHR return line 1-1012B-16"	603	X		X	
M	1-9	Drywell; RHR shutdown cooling supply line 1-1025-20"	601	X		X	

*M = Mechanical Snubber
H = Hydraulic Snubber

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
M	1-10	Drywell; RHR shutdown cooling supply line 1-1025-20"	601	X		X	
M	1-11	Drywell; "A" recirculation pump to shield wall	586 at 135°	X	X	X	
M	1-12	Drywell; "B" recirculation pump to shield wall	586 at 315°	X	X	X	
M	1-13	Drywell; "A" recirculation pump to support	586 at 146.5°	X	X	X	
M	1-14	Drywell; "B" recirculation pump to support	586 at 304°	X	X	X	
M	1-15	Drywell; "B" recirculation pump to support	586 at 326.5°	X	X	X	
M	1-16	Drywell; recirculation ring header	610 at 90°	X	X	X	
M	1-17	Drywell; recirculation ring header	610 at 270°	X	X	X	
M	1-18	Drywell; "A" recirculation pump motor to support	612 at 135°	X	X	X	

*M = Mechanical Snubber
H = Hydraulic Snubber

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
M	1-19	Drywell; "B" recirculation pump motor to support	612 at 315°	X	X	X	
M	1-20	Drywell; recirculation ring header to support	612 at 195°	X	X	X	
M	1-21	Drywell; "A" recirculation pump to support	588 at 124°	X	X	X	
M	1-22	Drywell; "A" recirculation pump motor to shield wall	602 at 122°	X		X	
M	1-23	Drywell; "A" recirculation pump motor to shield wall	602 at 148°	X		X	
M	1-24	Drywell; "B" recirculation pump motor to shield wall	602 at 302°	X		X	
M	1-25	Drywell; "B" recirculation pump motor to shield wall	602 at 328°	X		X	
M	1-26	Drywell; main steam relief valve 1-203-3A	619	X	X	X	
M	1-27	Drywell; main steam relief valve 1-203-3A	619	X	X	X	

*M = Mechanical Snubber
H = Hydraulic Snubber

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
M	1-28	Drywell; main steam relief vaive 1-203-3A	619	X		X	
M	1-29	Drywell; main steam relief valve 1-203-3A	619	X	X	X	
M	1-30	Drywell; northeast end of CRD cluster	605	X		X	
M	1-31	Drywell; northwest end of CRD cluster	605	X		X	
M	1-32	Drywell; southeast end of CRD cluster	605	X		X	
M	1-33	Drywell; southwest end of CRD cluster	605	X		X	

*M = Mechanical Snubber
H = Hydraulic Snubber

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
H	1-36	Reactor bldg; RHR shutdown cooling supply line 1-1025-20"	590				X
H	1-37	Reactor bldg; RHR shutdown cooling supply line 1-1024A-20"	573		X		X
H	1-38	Reactor bldg; RHR shutdown cooling supply line 1-1024A-20"	573		X		X
H	1-39	Reactor bldg; RHR shutdown cooling supply line 1-1024A-20"	573		X		X
H	1-40	Reactor bldg; RHR shutdown cooling supply line 1-1024A-20"	573		X		X
H	1-41	Reactor bldg; RHR pump supply line 1-1015A-24"	562	X			X
H	1-42	Reactor bldg; RHR pump supply line 1-1015-24"	562	X			X
H	1-43	Drywell; Recirc line 1-201-22"	610	X	X	X	

*M = Mechanical Snubber
H = Hydraulic Snubber

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
M	1-44	Drywell; Recirc line 1-201C-12"	614	X	X	X	
M	1-45	Drywell; Recirc line 1-201M-12"	614	X	X	X	
M	1-46	Drywell; Recirc line 1-201B-28"	613	X	X	X	
M	1-47	Drywell; Recirc line 1-201C-12"	613	X	X	X	
M	1-48	Drywell; Recirc line 1-202A-28"	594	X	X	X	
M	1-49	Drywell; RHRS line 1-1011-4"	627	X	X	X	
M	1-50	MSIV Rm; Main Steam line 1-3001A-24"	615	X	X		X
M	1-51	MSIV Rm; Main Steam line 1-3001A-24"	615	X	X		X

*M = Mechanical Snubber
H = Hydraulic Snubber

Table 3.6-1

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Type*	Snubber Number	Location	Elevation (feet)	Snubber in High Radiation Area During Shutdown	Snubbers Especially Difficult to Remove	Snubbers Inaccessible During Normal Operation	Snubbers Accessible During Normal Operation
M	1-52	MSIV Rm; Main Steam line 1-3001B-24"	615	X	X		X
M	1-53	MSIV Rm; Main Steam line 1-3001B-24"	615	X	X		X
M	1-54	MSIV Rm; Main Steam line 1-3001C-24"	615	X	X		X
M	1-55	MSIV Rm; Main Steam line 1-3001C-24"	615	X	X		X
M	1-56	MSIV Rm; Main Steam line 1-3001D-24"	615	X	X		X
M	1-57	MSIV Rm; Main Steam line 1-3001D-24"	615	X	X		X

*M = Mechanical Snubber
H = Hydraulic Snubber

Fig. 3.6-1

Minimum Temperature Requirements per Appendix G of 10 CFR 50

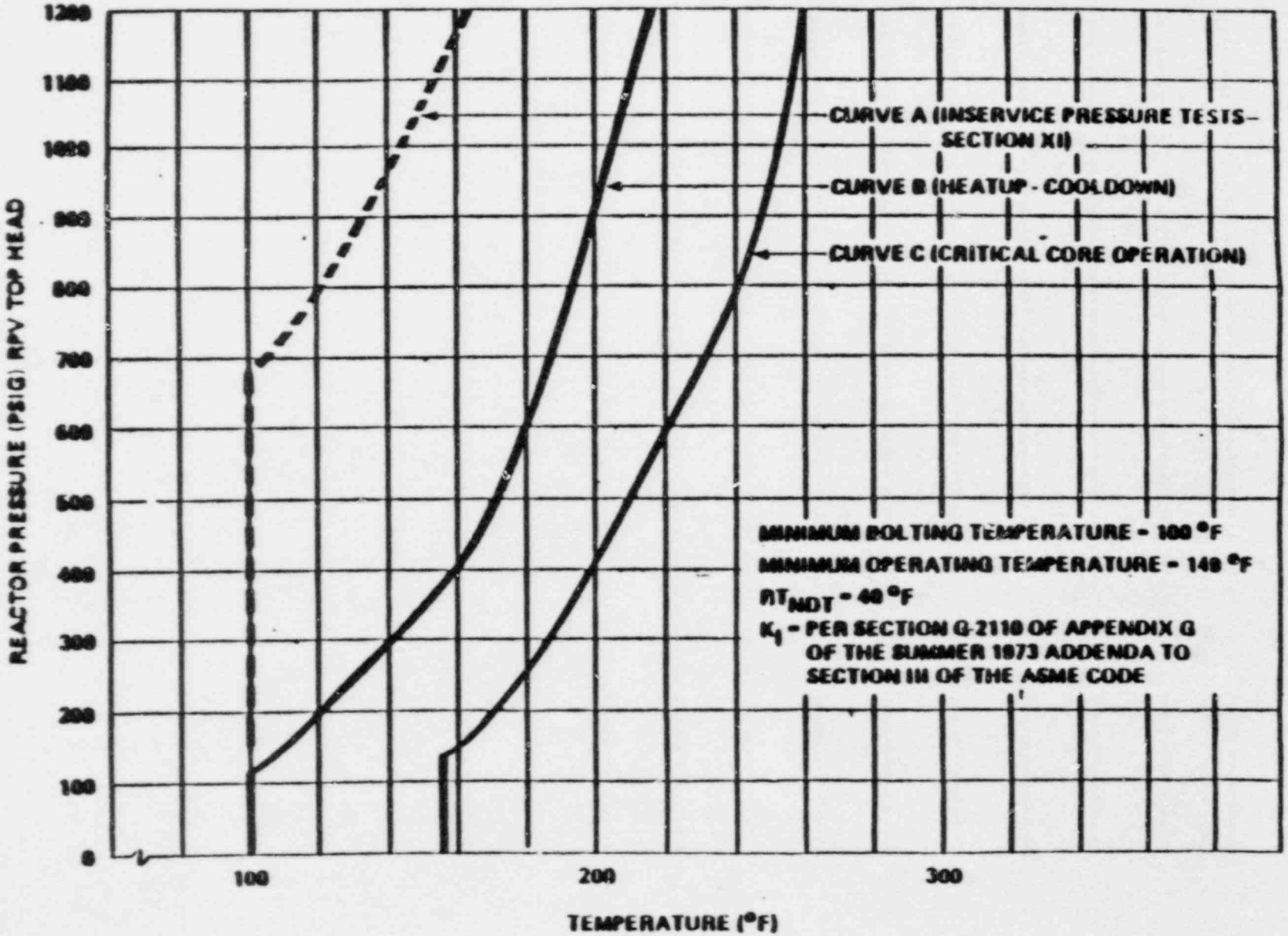


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TABLE 4.6-1

INSERVICE INSPECTION REQUIREMENTS FOR QUAD-CITIES

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]
A	Longitudinal and circumferential shell welds in core region			Note: Not applicable with present plant design.
B	Longitudinal and circumferential welds in shell (other than those of categories A and C) and meridional and circumferential seam welds in bottom head and closure head (other than those of Category C)	Volumetric	During each 10-year inspection interval (for 10% of each longitudinal and meridional 5% circumferential length seam)	Accessible top 10 feet of vertical vessel weld in two places (100% inspected in 10 years for approximately 2 feet each refueling outage).
				10% of meridional seam welds in vessel closure head and 5% of circumferential welds in vessel closure head
				Note: Bottom head closure not applicable with present plant design.
C	Vessel-to-flange and head-to-flange circumferential welds	Volumetric	Cumulative 100% coverage at end of 10-year interval	Equivalent to 10% of vessel-to-flange and head-to-flange circumferential weld area each refueling outage
D	Primary nozzle-to-vessel and nozzle-to-head welds and nozzle-to-vessel, nozzle-to head inside radiused section	Volumetric	Cumulative 100% coverage at end of 10-year interval	Nozzle welds: Recirculation outlet[2]: once every 5 years Recirculation inlet[10]: at least once each refueling outage

TABLE 4.6-1 (cont'd)

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]
				Core spray inlet[2]: once every 5 years Control rod drive return[1]: once every 10 years Standby liquid control[1]: once every 10 years Head instrumentation[2]: once every 5 years Head spray inlet[1]: once every 10 years
E	Partial penetration welds including control rod drive penetrations and vessel instrumentation nozzles	Visual	The examinations performed during each inspection interval shall cover at least 25% of each group of penetrations of comparable size and function	The area surrounding each penetration shall be examined for evidence of leakage during pressure testing
F	Primary nozzles to safe-end welds	Visual, surface, and volumetric	Cumulative 100% coverage at end of 10-year interval	Safe-ended nozzles: Recirculation outlet[2]: once every 5 years Recirculation inlet[10]: at least once each refueling outage Core spray inlet[2]: once every 5 years Control rod drive[1]: once every 10 years Standby liquid control[1]: once every 10 years Head instrumentation[2]: once every 5 years Head spray inlet[1]: once every 10 years

TABLE 4.6-1 (cont'd)

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]
G-1	Closure studs and nuts	Volumetric and visual or surface	Cumulative 100% coverage at end of 10-year interval	100% of vessel studs and nuts will be inspected each refueling outage
	Ligaments between threaded stud holes	Volumetric	Cumulative 100% coverage at end of 10-year interval	Equivalent to 10% of ligaments each refueling outage. Examination of bushings, threads, and ligaments in base material of flanges may be performed from the face of the flange and are required to be examined only when the connection is disassembled
	Closure washers, bushings	Visual	Cumulative 100% coverage at end of 10-year interval	Equivalent to 10% of washers each refueling outage, bushings not applicable with present design.
	Pressure-retaining bolting $\geq$ 2 inch diameter	Visual and volumetric	Cumulative 100% coverage at end of 10-year interval	Equivalent to 10% of recirculating pump bolts each refueling outage.
G-2	Pressure-retaining bolting < 2 inch diameter	Visual	Cumulative 100% of coverage at end of 10-year interval	Bolting will be examined when bolting is removed or when the bolted connected is broken or disassembled. For bolting which is not removed or where the bolted connection is not broken, the inspection will consist of a visual examination to detect signs of distress or evidence of leaking.

TABLE 4.6-1 (cont'd)

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]
H	Integrally welded vessel supports	Volumetric	During 10-year interval	10% (approximately 8 ft) of lineal feet of vessel support skirt welding in 10th year.
I	Closure head cladding	Visual and surface or volumetric	During 10-year interval	During the 10-year interval, at least six patches (each 36 in^2) evenly distributed in the closure head.
	Vessel cladding	Visual	During 10-year interval	6 patches (each 36 in^2) evenly distributed in the accessible sections of the vessel shell shall be examined.

TABLE 4.6-1 (cont'd)

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]		
				System	Pipe Sizes	Unit 1 Total Welds
J	Circumferential and longitudinal pipe welds (Refer to Note 2 at the end of this table for a breakdown of these welds.)	Visual and volumetric	Cumulative 25% of all weld joints (selectively distributed among the higher stress joints in entire system) every 10 years. Group I and Group II welds (See Note 1 for location breakdown) on main feedlines and main steamlines shall be inspected in 10 years during the first period. At least 25% of the welds shall be inspected at approximately each 2-1/2-year interval. Group I welds shall be inspected during each 10-year period thereafter.	Shutdown cooling	20-in.	17
				RCIC	3-in., 4-in.	33
				Reactor water cleanup	4-in., 6-in.	27
				CRD hydraulic system	3-in., 4-in.	18
				RHR	16-in.	29
				Head spray	4-in.	28
				Core spray piping	10-in.	32
				HPCI	10-in., 14-in.	22
				Feed piping	4-in., 12-in., 18-in.	96
				Recirculation	4-in., 12-in.	
				Main Steam	22-in., 22-in., 28-in.	133
					3-in., 20-in.	119
K-1	Integrally-welded external support attachments for piping, valves, and pumps	Visual and volumetric	100% cumulative in first 10 years 25% cumulative in each following 10-year inspection interval	Welds to the pressure-containing boundary, the base metal beneath the weld zone, and along the support attachment member for a distance of two base metal thicknesses.		

TABLE 4.5-1 (cont'd)

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]
K-2	Support members and structures for piping, valves, and pumps whose structural integrity is relied upon to withstand design loads and seismic-induced displacements.	Visual	100% cumulative during each 10-year inspection interval	Support settings of constant and variable spring type hangers, snubbers, and shock absorbers shall be inspected to verify proper distribution of design loads among the associated support components.
L-1	Pump casing welds	Visual and volumetric	One pump of each type during 10-year interval	Not applicable with present plant design.
L-2	Pump casings	Visual	One pump of each type during 10-year interval if disassembled	One recirculating pump in 10 years.
M-1	Welds in valve bodies 3 inches and above	Visual and volumetric	One valve of each type during 10-year interval	Not applicable with present plant design
M-2	Valve bodies 3 inches and above	Visual	One valve of each type during 10-year interval if disassembled	One disassembled valve (with or without welds and 3 inches over in normal size) in each category and type shall be subject to visual examination. Individual examination shall cover 100% of the pressure boundary welds and may be performed at or near the end of the 10-year interval.

TABLE 4.6-1 (cont'd)

Category	Component Parts to be Examined	Examination Method	Frequency of Examination	Examinations[1]
N	Interior surfaces and internals and integrally welded internal supports of the reactor vessel, including core spray spargers, core spray nozzles, and upper portions of jet pumps	Visual (not Inservice Inspection Code)	During first refueling outage and during subsequent refueling outages at approximately 3-year intervals	Interior surfaces and internal components of the reactor vessel, including the space at the bottom head and internal attachments which are welded to the vessel made accessible by the removal of components during normal refueling operations. All internal attachments whose failure may adversely affect core integrity shall be examined.
O	Control rod drive housing pressure-retaining welds.	Volumetric	The examinations performed during each inspection interval shall include the welds in 10% of the peripheral control rod drive housings.	The areas shall include the weld metal and base metal for one weld thickness beyond the edge of the weld.

Notes

1. Extent of Examinations

   Examinations which reveal unacceptable structural defects in a category shall be extended to include an additional number (or areas) of system components or piping in the same category approximately equal to those initially examined. In the event further unacceptable structural defects are revealed, all remaining system components or piping in the category shall be examined to the extent specified in that examination category.

TABLE 4.6-1 (cont'd)

2. Category J Weld Breakdown

Main Steamline - Group I Welds

Line	Weld Identification Unit 1
3001A-20-in.	30A-S11
3001B-20-in.	30B-S10
3001C-20-in.	30C-S10
3001D-20-in.	30D-S10

Group II Welds

Line	Weld Identification Unit 1
3001A-20-in.	30A-S22
	30A-F23
	30A-F24
3001B-20-in.	30B-S25
	30B-F26
	30B-F27
3001C-20-in.	30C-S21
	30C-F22
	30C-F23
3001D-20-in.	30D-S20
	30D-F21
	30D-F22

Feedwater Line - Group I Welds

Line	Weld Identification Unit 1
3204A-18-in.	32A-S5
3204B-18-in.	32B-S4

Group II Welds

Line	Weld Identification Unit 1
3204A-18-in.	32A-S1
	32A-F3
	32A-F7
3204B-18-in.	32B-S1
	32B-F6
3204C-12-in.	32C-S4
3204D-12-in.	32D-S4
	32D-S8
3204E-12-in.	32E-F9
	32D-S2
3204F-12-in.	32F-S2
	32F-F6

3. Supplemental Inspection Program for First and Second Refueling Outages

a. The following critical and sensitized components shall be nondestructively examined by the methods indicated:

Component	Examination Method
Bimetallic welds of field-replaced safe-ends	PT and (UT or RT)

TABLE 4.6-1 (cont'd)

b. The areas subject to examination shall include 100% of the exterior surfaces of the welds in Item 1. Weld areas to be examined shall include the base material for at least one wall thickness beyond the edge of the weld.

c. All examinations shall be conducted in accord with the examination techniques and procedures and meet the acceptance standards specified in the ASME Section XI Inservice Inspection Code and supplemented where necessary by special techniques with demonstrated capability to detect stress-corrosion cracking.

d. The examination frequency shall conform to the following schedule:

Bimetallic welds of field-replaced safe-ends

1) 25% at or within the first refueling outage 2) 25% at or within the second refueling outage

e. In the event any of the examinations for Item 4 reveal indications of structural defects which upon evaluation require repairs or replacements, the specified examination frequency shall be subject to review by the NRC.

TABLE 4.6-2

REVISED WITHDRAWAL SCHEDULE FOR QUAD-CITIES UNIT 1

Withdrawal Year	Part No.	Location	Comments
1982	8	Wall - 215°	
2002	7	Wall - 95°	
	9	Wall - 245°	Standby
	5	Wall - 65°	Standby
	10	Wall - 275°	Standby
1981	4	Near Core Top Guide - 90°	
1984	6	Near Core Top Guide - 180°	

FIGURE 3.6-2

MINIMUM REACTOR PRESSURIZATION TEMPERATURE

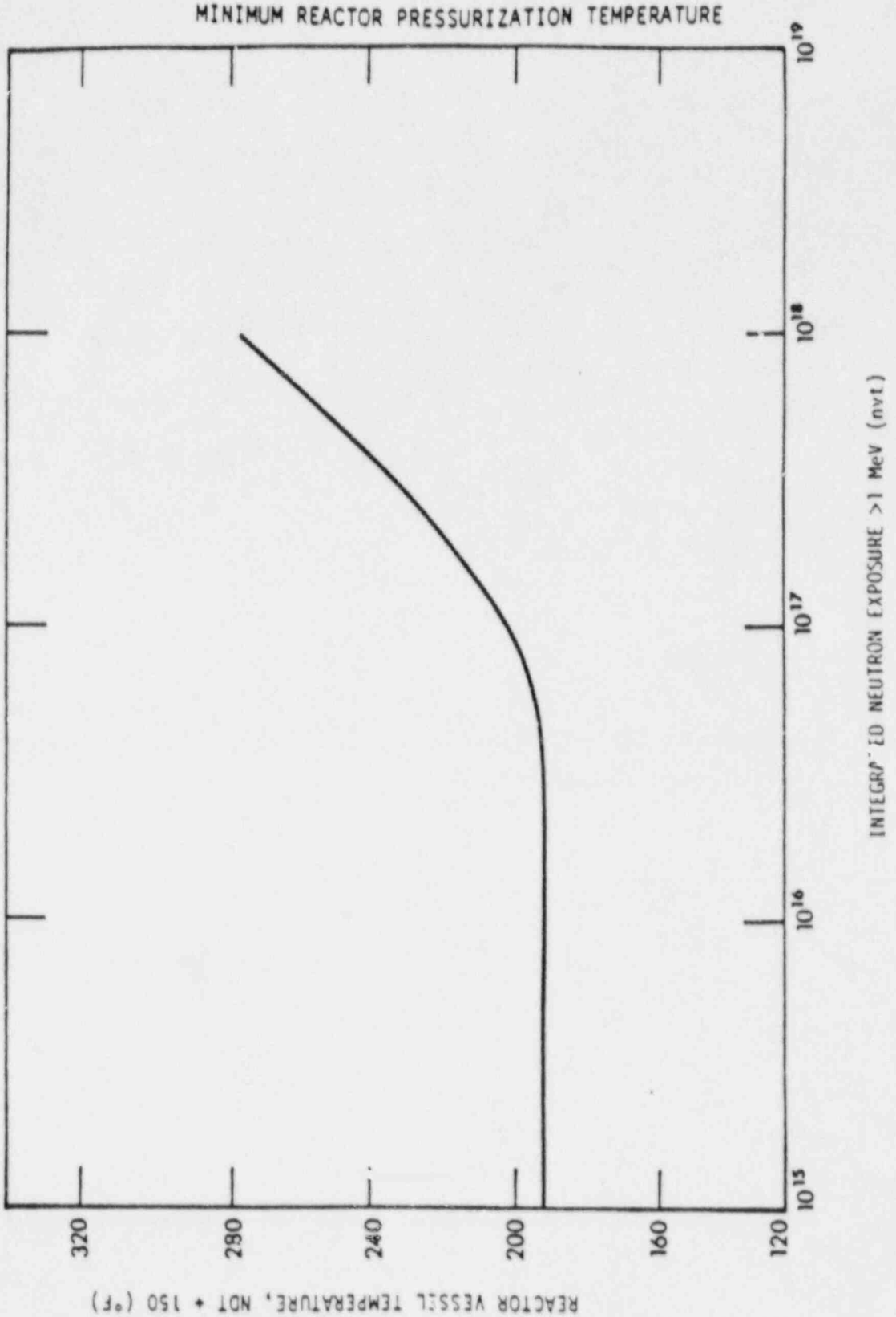
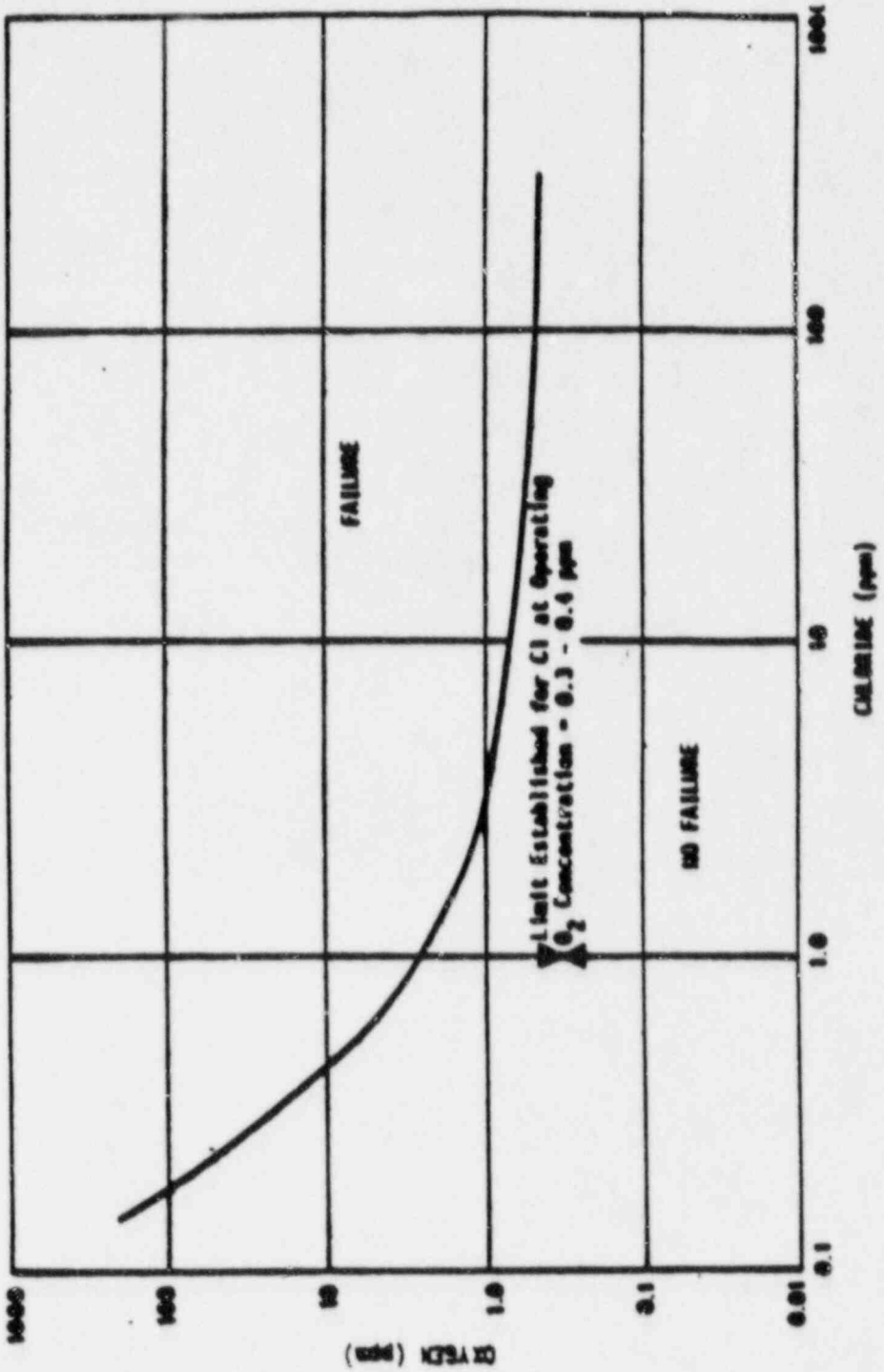


FIGURE 4.6-1

CHLORIDE STRESS CORROSION TEST RESULTS AT 500°F



3.7/4.7 CONTAINMENT SYSTEMS

LIMITING CONDITIONS FOR OPERATION

Applicability:

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

Objective:

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

SURVEILLANCE REQUIREMENTS

Applicability;

Applies to the primary and secondary containment integrity.

Objective:

To verify the integrity of the primary and secondary containment.

SPECIFICATIONS

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, except as permitted by Specification 3.5.F.2, 3.5.F.3, or 3.5.F.4, the suppression pool water volume and temperature shall be maintained within the following limits:

   a. maximum water volume: 115,655 ft^3 during normal operation; shown on level indicator as +2 inches;

   b. minimum water volume: 112,200 ft^3; shown on level indicator as -2 inches; and

A. Primary Containment

1. Suppression chamber water level and temperature; suppression chamber visual inspection.

   a. The suppression pool water level and temperature shall be checked once per day.

   b. Whenever there is indication of relief valve operation or testing which adds heat to the suppression pool, the pool temperature shall be continually monitored and also observed and logged every 5 minutes until the heat addition is terminated.

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 Item 1. In connection with such testing, the pool temperature must be reduced to below normal power operation limit specified in Item 1 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 operation limit specified in Item 1.

4) During reactor isolation conditions, the reactor pressure vessel shall be depressurized to less than 150 psig at normal cooldown rates if the pool temperature reaches 120°F.

d. Maximum downcomer submergence 3.54 ft.

e. Minimum downcomer submergence 3.21 ft.

c. Whenever there is indication of relief valve operation with the temperature of the suppression pool reaching 160°F or more and the primary coolant system pressure greater than 150 psig, an external visual examination of the suppression chamber shall be conducted before resuming power operation.

d. A visual inspection of the suppression chamber interior, including water line regions, shall be made at each major refueling outage.

2. Primary containment integrity shall be maintained at all times when the reactor is critical or when the reactor water temperature is above 212°F and fuel is in the reactor vessel except while performing low power physics tests at atmospheric pressure at power levels not to exceed 5 MWt.

   a. When primary containment integrity is required, primary containment leakage rates shall be limited to:

      1) An overall integrated leakage rate of:

         a) $\leq L_a$, 1.0 percent by weight of the containment air per 24 hours at P_a, 48 psig, or

         b) $\leq L_t$, 1.0 percent by weight of the containment air per 24 hours at a reduced pressure of P_t, 25 psig.

      2) A combined leakage rate of $\leq 0.60\ L_a$ for all penetrations and valves, except the main steam isolation valves, and the MO1-220-1 valve (while it is inoperable), subject to Type B and C tests when pressurized to P_a. The MO1-220-1 valve will be restored to operability no later than startup after the first Cold Shutdown following a 30-day period after December 21, 1982.

2. The containment leakage rates shall be demonstrated at the following test schedule, and shall be determined in conformance with the criteria specified in Appendix J of 10 CFR 50 using the methods and provisions of ANSI N45.4 (1972).

   a. Three Type A tests (Overall Integrated Containment Leakage Rate) shall be conducted at 40 ± 10 month intervals during shutdown at either P_a, 48 psig, or at P_t, 25 psig during each 10-year service period. The third test of each set shall be conducted during the shutdown for the 10-year plant inservice inspection.

3) 11.5 scf per hour for any one main steam isolation valve when tested at 25 psig.

b. With the measured overall integrated containment leakage rate exceeding 0.75 L_a or 0.75 L_t, as applicable, restore the overall integrated leakage rate(s) to $\leq$ 0.75 L_a or $\leq$ 0.75 L_t, as applicable.

c. With the measured combined leakage rate for all penetrations and valves, except for main steam isolation valves, subject to Type B and C tests exceeding 0.60 L_a, restore the combined leakage rate for all penetrations and valves, except for main steam isolation valves, subject to Type B and C tests to 0.60 L_a.

b. If any periodic Type A test fails to meet either 0.75 L_a or 0.75 L_t, the test schedule for subsequent Type A tests shall be reviewed and approved by the commission. If two consecutive Type A tests fail to meet either 0.75 L_a or 0.75 L_t, a Type A test shall be performed at least every 18 months until two consecutive Type A tests meet either 0.75 L_a or 0.75 L_t, at which time the above test schedule may be resumed.

c. The accuracy of each Type A test shall be verified by a supplemental test which:

1) Confirms the accuracy of the test by verifying that the difference between the supplemental data and the Type A test data is within 0.25 L_a or 0.25 L_t.

2) Has a duration sufficient to establish accurately the change in leakage rate between the Type A test and the supplemental test.

3) Requires the quantity of gas injected into the containment or bled from the containment during the supplemental test to be equivalent to at least 25 percent of the total measured leakage at P_a, 48 psig, or P_t, 25 psig.

d. Leakage shall be limited to a leakage rate of less than or equal to 3.75 percent of L_a for any one air lock when pressurized to 10 psig.

d. Type B and C tests shall be conducted at P_a, 48 psig, at intervals no greater than 24 months except for tests involving:

1) Air locks which shall be tested at 10 psig at least once per 18 months, and

2) Main steam isolation valves, which shall be leak tested at least once per 18 months at a pressure of 25 psig.

3) Bolted double-gasketed seals which shall be tested at a pressure of 48 psig whenever the seal is closed after being opened and each operating cycle.

4) While valve MO1-220-1 is inoperable, valves MO1-220-2, MO1-220-3, and MO1-220-4 shall be VERIFIED closed after each closure.

e. With the measured leakage rate exceeding 11.5 scf per hour for any one main steam isolation valve, restore the leakage rate to ≤ 11.5 scf per hour for any one main steam isolation valve prior to increasing the reactor coolant temperature above 212°F.

e. All test leakage rates shall be calculated using observed data converted to absolute values. Error analyses shall be performed to select a balanced integrated leakage measurements system.

3. Pressure Suppression Chamber-Reactor Building Vacuum Breakers

a. Except as specified in Specifications 3.7.A.3.b below, two pressure suppression chamber-reactor building vacuum breakers in each line shall be operable at all times when the primary containment integrity is required. The setpoint of the differential pressure instrumentation which actuates the pressure suppression chamber-reactor building air-operated vacuum breakers shall not exceed 0.5 psid. The vacuum breakers shall open fully when subjected to a force equivalent to or less than 0.5 psid acting on the valve disk.

b. From and after the date that one of the pressure suppression chamber-reactor building vacuum breakers is made or found to be inoperable for any reason, the vacuum breaker shall be locked closed and reactor operation be permissible

3. Pressure Suppression Chamber-Reactor Building Vacuum Breakers

a. The pressure suppression chamber-reactor building vacuum breakers and associated instrumentation, including setpoint, shall be checked for proper operation every 3 months.

b. During each refueling outage each vacuum breaker shall be tested to determine that the force required to open it does not exceed the force specified in Specification 3.7.A.3.a; each vacuum breaker shall also be inspected and verified to meet design requirements.

only during the succeeding 7 days unless such vacuum breaker is sooner made operable, provided that the procedure does not violate primary containment integrity.

4. Pressure Suppression Chamber-Drywell Vacuum Breakers

a. When primary containment is required, all pressure suppression chamber-drywell vacuum breakers shall be operable except during testing and as stated in Specification 3.7.A.4.b, c, and d, below. Pressure suppression chamber-drywell vacuum breakers shall be considered operable if:

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

2) The valve can be closed by gravity when released after being opened by remote or manual means to within the equivalent of 1/16 inch at all points along the seal surface of the disk.

4. Pressure Suppression Chamber-Drywell Vacuum Breakers

a. Periodic Operability Tests

1) Once each month each pressure suppression chamber-drywell vacuum breaker shall be exercised. Operability of valves, position switches, and position indicators and alarms shall be verified.

2) A drywell to suppression chamber differential pressure decay rate test shall be conducted at least every 3 months.

3) The position alarm system will annunciate in the control room if the valve opening exceeds the equivalent of 1/16 inch at all points along the seal surface of the disk.

b. Any pressure suppression chamber-drywell vacuum breaker may be non-fully closed as indicated by the position indication and alarm systems provided that drywell to suppression chamber differential pressure decay rate is demonstrated to be not greater than 25% of the differential pressure decay rate for all vacuum breakers open the equivalent of 1/16 inch at all points along the seal surface of the disk.

b. During each refueling outage:

1) The pressure suppression chamber-drywell vacuum breakers shall be tested to determine the force required to open each valve from fully closed to fully open.

2) Vacuum breaker position indication and alarm systems shall be calibrated and functionally tested.

3) At least 25% of the vacuum breakers shall be inspected such that all vacuum breakers shall have been inspected following every fourth refueling outage. If deficiencies are found, all vacuum breakers shall be inspected and deficiencies corrected.

4) A drywell to suppression chamber leak test shall demonstrate that with initial differential pressure of not less than 1.0 psi, the differential pressure decay rate does not exceed the rate which would occur through a 1-inch orifice without the addition of air or nitrogen.

c. Reactor operation may continue provided that no more than one quarter of the number of pressure suppression chamber-drywell vacuum breakers are determined to be inoperable provided that they are secured or known to be in the closed position.

d. If failure occurs in one of the two-position alarm systems for one or more vacuum breakers, reactor operation may continue provided that a differential pressure decay rate test is initiated immediately and performed every 15 days thereafter until the failure is corrected. The test shall meet the requirements of Specification 3.7.A.4.b.

5. Oxygen Concentration

a. After completion of the startup test program and demonstration of plant electrical output, the primary containment atmosphere shall be reduced to less than 4% oxygen by volume with nitrogen gas during reactor power operation with reactor coolant pressure above 90 psig, except as specified in Specification 3.7.A.5.b.

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

5. Oxygen Concentration

The primary containment oxygen concentration shall be measured and recorded on a weekly basis.

6. Containment Systems

Drywell-Suppression Chamber Differential Pressure

a. Differential pressure between the drywell and suppression chamber shall be maintained at equal to or greater than 1.20 psid except as specified in (1), (2), and (3) below:

1) This differential shall be established within the 24 hour period subsequent to placing the reactor mode switch into the RUN mode during a startup and may be relaxed 24 hours prior to reactor shutdown when the provisions of 3.7.A.5.b apply.

2) This differential may be decreased to less than 1.20 psid for a maximum of 4 hours during required operability testing of the HPCI system pump, the RCIC system pump, the drywell-pressure suppression chamber vacuum breakers, and reactor pressure relief valves.

3) If the Specifications of 3.7.A cannot be met, and the differential pressure cannot be restored within the subsequent six (6) hour

6. Containment Systems

Drywell-Suppression Chamber Differential Pressure

a. The pressure differential between the drywell and suppression chamber shall be recorded at least once each shift.

period, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition in the following 24 hours.

B. Standby Gas Treatment System

1. Two separate and independent standby gas treatment system circuits shall be operable at all times when secondary containment integrity is required, except as specified in sections 3.7.B.1.(a) and (b).

   a. After one of the standby gas treatment system circuits is made or found to be inoperable for any reason, reactor operation and fuel handling is permissible only during the succeeding 7 days, provided that all active components in the other standby gas treatment system shall be demonstrated to be operable within 2 hours and daily thereafter. Within 36 hours following the 7 days, the reactor shall be placed in a condition for which the standby gas treatment system is not required in accordance with Specification 3.7.C.1(a) through (d).

B. Standby Gas Treatment System

1. At least once per month, initiate from the control room 4000 cfm (± 10%) flow through both circuits of the standby gas treatment system for at least 10 hours with the circuit heaters operating at rated power.

   a. Within 2 hours from the time that one standby gas treatment system circuit is made or found to be inoperable for any reason and daily thereafter for the next succeeding 7 days, initiate from the control room 4000 cfm (± 10%) flow through the operable circuit of the standby gas treatment system for at least 10 hours with the circuit heaters operating.

b. If both standby gas treatment system circuits are not operable, within 36 hours the reactor shall be placed in a condition for which the standby gas treatment system is not required in accordance with Specification 3.7.C.1.(a) through (d).

2. Performance Requirement (See Note 1)

a. Periodic Requirements

1) The results of the in-place DOP tests at 4000 cfm (± 10%) on HEPA filters shall show ≤ 1% DOP penetration.

2) The results of inplace halogenated tests at 4000 cfm (± 10%) on charcoal banks shall show ≤ 1% penetration.

2. Performance Requirement Tests (See Note 1)

a. At least once per 1440 hours of system operation; or once per operating cycle but not to exceed 18 months, whichever occurs first; or following painting, fire, or chemical release in any ventilation zone communicating with the system while the system is operating that could contaminate the HEPA filters or charcoal adsorbers, perform the following:

1) In-place DOP test the HEPA filter banks to verify leaktight integrity.

2) In-place test the charcoal adsorber banks with halogenated hydrocarbon tracer to verify leaktight integrity.

3) The results of laboratory carbon sample analysis shall show ≥ 90% methyl iodide removal efficiency when tested at 130°C and 95% R.H.

3. Postmaintenance Requirements (See Note 1)

a. After any maintenance or heating that could affect the HEPA filter or HEPA filter mounting frame leak-tight integrity, the results of the in-place DOP tests at 4000 cfm (± 10%) on HEPA filters shall show ≤ 1% DOP penetration in accordance with Specification 3.7.B.2.a(1).

3) Remove one carbon test canister from the charcoal adsorber. Subject this sample to a laboratory analysis to verify methyl iodide removal efficiency.

b. At least once per operating cycle, but not to exceed 18 months, the following conditions shall be demonstrated:

1) Pressure drop across the combined filters of each standby gas treatment system circuit is less than 6 inches of water at 4000 cfm (± 10%) flow rate.

2) Operability of inlet heater at rated power.

3) Automatic initiation of each standby gas treatment system circuit.

3. Postmaintenance Testing (See Note 1)

a. After any maintenance or testing that could affect the leaktight integrity of the HEPA filters, perform in-place DOP tests on the HEPA filters in accordance with Specification 3.7.B.2.a(1).

b. After any maintenance or testing that could affect the charcoal adsorber leak-tight integrity, the results of in-place halogenated hydrocarbon tests at 4000 cfm (± 10%) shall show ≤ 1% penetration in accordance with Specification 3.7.B.2.a(2).

c. The results of in-place air distribution tests shall show the air distribution is uniform within ±20% to each HEPA filter when tested initially and after any maintenance or testing that could affect the air distribution within the standby gas treatment system.

b. After any maintenance or testing that could affect the leaktight integrity of the charcoal adsorber banks, perform halogenated hydrocarbon tests on the charcoal adsorbers in accordance with Specification 3.7.B.2.a.(2).

c. Perform an air distribution test on the HEPA filter bank initially and after any maintenance or testing that could affect the air distribution within the standby gas treatment system. The test shall be performed at 4000 cfm (± 10%) flow rate.

4. Standby gas treatment system surveillance shall be performed as indicated below:

a. At least once per operating cycle it shall be demonstrated that:

1) Pressure drop across the combined high-efficiency and charcoal filters is less than 5.7 inches of water at 4000 cfm and

2) Inlet heater Δ T shall be a minimum of 14°F at 4000 cfm.

b. At least once during each scheduled secondary containment leak rate test, whenever a filter is changed, whenever work is performed that could affect the filter system efficiency and at intervals not to exceed 6 months between refueling outages, it shall be demonstrated that:

1) The removal efficiency of the particulate filters is not less than 99% for particulate matter larger than 0.7 micron.

2) No bypassing of the filter occurs, based on a freon 12 test. This test is considered satisfactory if 99% of the freon introduced is retained by the filters.

c. At least once each 5 years removable charcoal cartridges shall be removed and adsorption shall be demonstrated.

d. At least once per operating cycle automatic initiation of each branch of the standby gas treatment system shall be demonstrated.

e. At least once per operating cycle manual operability of the bypass valve for filter cooling shall be demonstrated.

Note 1: Because the accomplishment of Specifications 3.7.B.2, 3.7.B.3, 4.7.B.2 and 4.7.B.3 will require equipment modifications, their implementation will be delayed until about December 31, 1976. Until that time, the surveillance requirements of Specification 4.7.B.4 shall apply.

C. Secondary Containment

1. Secondary containment integrity shall be maintained during all modes of plant operation except when all of the following conditions are met:

   a. The reactors are subcritical and Specification 3.3.A is met.

   b. The reactor water temperature is below 212°F and the reactor coolant systems are vented.

C. Secondary Containment

1. Secondary containment surveillance shall be performed as indicated below:

   a. A preoperational secondary containment capability test shall be conducted after isolating the reactor building and placing either standby gas treatment system filter train in operation. Such tests shall demonstrate the capability to maintain an average 1/4 inch of water vacuum under calm wind ($2<\bar{u}<5$ mph) conditions with a filter train flow rate of not more than 4000 CFM.

   b. Additional tests shall be performed during the first operating cycle under an adequate number of different environmental wind conditions to enable valid extrapolation of the test results.

c. No activity is being performed which can reduce the shutdown margin below that specified in Specification 3.3.A.

d. The fuel cask or irradiated fuel is not being moved in the reactor building.

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

3. If Specification 3.7.C.1 cannot be met, procedures shall be initiated to establish conditions listed in Specifications 3.7.C.1 a through d.

D. Primary Containment Isolation Valves

1. During reactor power operating conditions, all isolation valves listed in Table 3.7-1 and all instrument line flow check valves which contact the primary coolant system shall be operable except as specified in Specification 3.7.D.2.

c. Secondary containment capability to maintain an average 1/4 inch of water vacuum under calm wind ($2 < u \leq 5$ mph) conditions with a filter train flow rate of not more than 4000 cfm shall be demonstrated at each refueling outage prior to refueling.

2. Whenever the LPCI mode of the RHR and core spray subsystems are required to be operable, the doors of the core spray and RHR pump compartments shall be verified to be closed weekly.

D. Primary Containment Isolation Valves

1. The primary containment isolation valves surveillance shall be performed as follows:

a. At least once per operating cycle the operable isolation valves that are power operated and automatically initiated shall be tested for simulated automatic initiation and closure times.

b. At least once per operating cycle the instrument line flow check valves shall be tested for proper operation.

c. At least once per quarter:

1) All normally open power operated isolation valves (except for the main steamline power-operated isolation valves) shall be fully closed and reopened.

2) The main steamline isolation valves (one at a time) shall be verified for closure time.

2. In the event any isolation valve specified in Table 3.7-1 becomes inoperable, reactor power operation may continue provided at least one valve in each line having an inoperable valve is in the mode corresponding to the isolated condition.

3. If Specifications 3.7.D.1 and 3.7.D.2 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

2. When an isolation valve listed in Table 3.7-1 is inoperable, the position of at least one other valve in each line having an inoperable valve shall be recorded daily.

4. The temperature of the main steamline air pilot valves shall be less than 170°F except as specified in Specifications 3.7.D.5 and 3.7.D.6 below.

5. From and after the date that the temperature of any main steamline air pilot valve is found to be greater than 170°F reactor operation is permissible only during the succeeding 7 days unless the temperature of such valve is sooner reduced to less than 170°F provided the main steamline isolation valves are operable.

6. If Specification 3.7.D.5 cannot be met, the main steamline isolation valve shall be considered inoperable and action taken in accordance with Specification 3.7.D.2.

3.7 LIMITING CONDITIONS FOR OPERATION BASES

A. Primary Containment

The integrity of the primary containment and operation of the emergency core cooling system, in combination, limit the offsite doses to values less than those suggested in 10 CFR 100 in the event of a break in the primary system piping. Thus, containment integrity is specified whenever the potential for violation of the primary reactor system integrity exists. Concern about such violation exists whenever the reactor is critical and above atmospheric pressure. An exception is made to this requirement during initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required. There will be no pressure on the system at this time, which will greatly reduce the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedure will be in effect again to minimize the probability of an accident occurring. Procedures and the rod worth minimizer would limit control rod worth to less than 1.0% Δk. A drop of a 1.0% Δk rod does not result in any fuel damage. In addition, in the unlikely event that an excursion did occur, the reactor building standby gas treatment system, which will be operational during this time, offers a sufficient barrier to keep offsite doses well within 10 CFR 100 guidelines.

The pressure suppression pool water provides the heat sink for the reactor primary system energy release following a postulated rupture of the system. The pressure suppression chamber water volume must absorb the associated decay and structural sensible heat released during primary system blowdown from 1000 psig.

Since all of the gases in the drywell are purged into the pressure suppression chamber air space during a loss-of-coolant accident, the pressure resulting from isothermal compression plus the vapor pressure of the liquid must not exceed 56 psig, the suppression chamber design pressure. The design volume of the suppression chamber (water and air) was obtained by considering that the total volume of reactor coolant to be condensed is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber (reference SAR section 5.2.3).

Using the minimum or maximum water volume given in the specification, containment pressure during the design-basis accident is approximately 48 psig, which is below the design value of 56 psig. Maximum water volume of 115,655 ft^3 results in a downcomer submergence of 4 feet; the minimum volume of 112,200 ft^3 results in a submergence approximately 4 inches less. The majority of the Bodega tests (Reference 1) were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to downcomer submergence, this specification is adequate.

Experimental data indicates 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.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a relief valve inadvertently opens or sticks open. This action would include: (1) use of all available means to close the valve, (2) initiation of suppression pool water cooling heat exchangers, (3) initiation of reactor shutdown, and (4) if other relief valves are use to depressurize the reactor, their discharge shall be separated from that of the stuck-open relief valve to assure mixing and uniformity of energy insertion to the pool.

The maximum temperature at the end of blowdown tested during the Humboldt Bay (Reference 2) and Bodega Bay tests was 170°F; this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperatures above 170°F.

Should it be necessary to drain the suppression chamber, this should only be done when there is no requirement for emergency core cooling systems operability as explained in Basis for Specification 3.5.F.

Using a 50°F rise (SAR Section 5.2.3.1) in the suppression chamber water temperature and maximum initial temperature of 95°F, a temperature of 145°F is achieved, which is well below the 170°F temperature which is used for complete condensation.

For an initial maximum suppression chamber water temperature of 95°F and assuming the normal complement of containment cooling pumps (2 RHR pumps and 2 RHR service water pumps), containment pressure is not required to maintain adequate net positive suction head (NPSH) for the core spray, LPCI mode of the RHR, and HPCI pumps.

If a loss-of-coolant accident were to occur when the reactor water temperature is below 330°F, the containment pressure would not exceed the 56 psig design pressure, even if no condensation were to occur. The maximum allowable pool temperature whenever the reactor is above 212°F shall be governed by this specification. Thus, specifying water volume-temperature requirements applicable for reactor water temperatures above 212°F provides additional margin above that available at 330°F.

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 structural integrity of the containment is maintained.

The vacuum relief system from the pressure suppression chamber to the reactor building consists of two 100% flow pipes each containing two vacuum relief breakers. Operation of either flow pipe will maintain the pressure differential less than 2 psig, the external design pressure of the primary containment. Redundancy of lines justifies reactor operation with one valve out of service for repairs for a period of 7 days.

The capacity of the pressure suppression chamber-drywell vacuum breakers is designed to limit the pressure differential between the suppression chamber and drywell to not greater than 0.5 psi during postaccident drywell cooling. They are sized on the basis of the Bodega Bay pressure suppression system test.

Based on these tests, design flow from the suppression chamber to the drywell can be obtained with 25% of the vacuum breakers closed without exceeding the 0.5 psi differential pressure limit.

Reactor operation is permissible if the bypass area between the primary containment drywell and suppression chamber does not exceed an allowable area. The allowable bypass area is based upon analysis considering primary system break area, suppression chamber effectiveness, and containment design pressure. Analyses show that the maximum allowable bypass area is equivalent to all vacuum breakers open the equivalent of 1/16 inch at all points along the seal surface of the disk (Reference 3).

Reactor operation is not permitted if differential pressure decay rate is demonstrated to exceed 25% of allowable, thus providing a margin of safety for the primary containment in the event of a small break in the primary system.

Each drywell-suppression chamber vacuum breaker is fitted with redundant pairs of position switches which provide signals of disk position to panel-mounted indicators and annunciate an alarm in the control room if the disk is open more than allowable. The alarm systems meet the intent of IEEE 279 standards. The quality of the alarm system justifies continued reactor operation for 15 days between differential pressure decay rate tests if one alarm system is inoperable for one or more vacuum breakers.

The relatively small containment volume inherent in the GE-BWR pressure suppression containment and the large amount of zirconium in the core are such that the occurrence of a very limited (1% or so) reaction of the zirconium and steam during a loss-of-coolant accident would lead to the liberation of sufficient hydrogen to result in a flammable concentration in the containment. Subsequent ignition of the hydrogen, if it is present in sufficient quantities to result in excessively rapid recombination, could result in a loss of containment integrity.

The 4% oxygen concentration by volume minimizes the possibility of hydrogen combustion following a loss-of-coolant accident. Significant quantities of hydrogen could be generated if the core cooling system did not sufficiently cool the core. Providing an LCO by volume is consistent with the fact that the oxygen analyzer indicated in % oxygen by volume.

The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is much more probable than the occurrence of the loss-of-coolant accident upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure.

The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration. The primary containment is normally slightly pressurized during periods of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase oxygen concentration. Once the containment is filled with nitrogen to the required concentration, no monitoring of oxygen concentration is necessary. However, at least once a week, the oxygen concentration will be determined as added assurance.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed (Reference 5) which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system and attached piping. The maintenance of a drywell-suppression chamber differential pressure of 1.20 psid and a suppression chamber water level corresponding to a downcomer submergence range of 3.21 to 3.54 feet will assure the integrity of the suppression chamber when subjected to post-LOCA suppression pool hydrodynamic forces.

B. Standby Gas Treatment System

The standby gas treatment system is designed to filter and exhaust the reactor building atmosphere to the chimney during secondary containment isolation conditions, with a minimum release of radioactive materials from the reactor building to the environs. One standby gas treatment system circuit is designed to automatically start upon containment isolation and to maintain the reactor building pressure at the design negative pressure so that all leakage should be in-leakage. Should one circuit fail to start, the redundant alternate standby gas treatment circuit is designed to start automatically.

Each of the two circuits has 100% capacity. Only one of the two standby gas treatment system circuits is needed to cleanup the reactor building atmosphere upon containment isolation. If one system is found to be inoperable, there is not immediate threat to the containment system performance. Therefore, reactor operation or refueling operation may continue while repairs are being made. If neither circuit is operable, the plant is placed in a condition that does not require a standby gas treatment system.

While only a small amount of particulates are released from the primary containment as a result of the loss-of-coolant accident, high-efficiency particulate filters before and after the charcoal filters are specified to minimize potential particular release to the environment and to prevent clogging of the charcoal adsorbers. The charcoal adsorbers are installed to reduce the potential release of radioiodine to the environment. (The in-place test results should indicate a system leaktightness of less than 1% bypass leakage for the charcoal adsorbers using halogenated hydrocarbon and a HEPA filter efficiency of at least 99% removal of DOP particulates).

Laboratory carbon sample test results indicate a radioactive methyl iodine removal efficiency for expected accident conditions. Operation of the standby gas treatment circuits significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers. If the performance requirements are met as specified, the calculated doses would be less than the guidelines stated in 10 CFR 100 for the accidents analyzed.

C. Secondary Containment

The secondary containment is designed to minimize any ground level release of radioactive materials which might result from a serious accident. The reactor building provides secondary containment during reactor operation, when the drywell is sealed and in service; the reactor building provides primary containment when the reactor is shutdown and the drywell is open, as during refueling. Because the secondary containment is an integral part of the complete containment system, secondary containment is required at all times that primary containment is required as well as during refueling, except, however, for initial fuel loading of Unit 1 prior to initial power testing (reference SAR Section 1).

D. Primary Containment Isolation Valves

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the pressure suppression system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a loss-of-coolant accident.

References

1. 'Bodega Bay Preliminary Hazards Summary Report,' Appendix 1, Docket 50-205, December 28, 1962.

2. C.H. Robbins, 'Tests of a Full Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment,' GEAP-3596, November 17, 1960.

3. Quad-Cities Special Report Number 4.

4. 'Nuclear Safety Program Annual Progress Report for Period Ending December 31, 1966, ORNL-4071.'

5. 'Quad-Cities Station Units 1 and 2 Short Term Program Plant Unique Torus Support and Attached Piping Analyses' August 1976 NUTECH Report Number COM-01-039.

4.7 SURVEILLANCE REQUIREMENTS BASES

A. Primary Containment

Because of the large volume and thermal capacity of the suppression pool, the vc'ume and temperature normally change very slowly, and monitoring these ımeters daily is sufficient to establish any temperature trends. By 'ring the suppression pool temperature to be continually monitored and tly logged during periods of significant heat addition, the ıre trends will be closely followed so that appropriate action can be The requirement for an external visual examination following any ıere potentially high loadings could occur provides assurance that no cant damage was encountered. Particular attention should be focused on structural discontinuities in the vicinty of the relief valve discharge since these are expected to be the points of highest stress.

The interiors of the drywell and suppression chamber are painted to prevent rusting. The inspection of the paint during each major refueling outage, approximately once per year, assures the paint is intact. Experience with this type of paint at fossil fuel-fired generating stations indicates that the inspection interval is adequate.

The primary containment preoperational test pressures are based upon the calculated primary containment pressure response in the event of a loss-of-coolant accident. The peak drywell pressure would be about 48 psig, which would reduce rapidly to 25 psig within 10 seconds following the pipe break. Following the pipe break, the suppression chamber pressure rises to 25 psig within 10 seconds, equalizes with drywell pressure, and therefore rapidly decays with the drywell pressure decay (SAR, section 5.2).

The design pressure of the drywell and absorption chamber is 56 psig (SAR, Section 5.2). The design leak rate is 0.5%/day at a pressure of 56 psig. As pointed out above, the pressure response of the drywell and suppression chamber following an accident would be the same after about 10 seconds. Based on the calculated containment pressure response discussed above, the primary containment preoperational test pressures were chosen. Also, based on the primary containment pressure response and the fact that the drywell and suppression chamber function as a unit, the primary containment will be tested as a unit rather than the individual components separately.

The design-basis loss-of-coolant accident was evaluated at the primary containment maximum allowable accident leak rate of 1.0%/day at 48 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 product release fractions stated in TID 14844, the maximum total whole body passing cloud dose is about 5 rem, and the maximum total thyroid dose is about 120 rem at the site boundary over an exposure duration of 2 hours.

The resultant doses that would occur for the duration of the accident at the low population distance of 3 miles are lower than those stated due to the variability of meterological 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 products from the primary containment through the filters and stack to the environs. Therefore, the specified primary containment leak rate and filter efficiency are conservative and provide margin between expected offsite doses and 10 CFR 100 guidelines.

Although the dose calculations suggest that the accident leak rate could be allowed to increase to about 2.6%/day before the guideline thyroid dose value given in 10 CFR 100 would be exceeded, establishing the test limit of 1.0%/day provides an adequate margin of safety to assure the health and safety of the general public. It is further considered that the allowable leak rate should not deviate significantly from the containment design value to take advantage of the design leaktightness capability of the structure over its service lifetime. Additional margin to maintain the containment in the as-built conditions is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable 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. 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 data reduction methods of ANSI N45.4-1972 will be applied for integrated leak rate tests.

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 suppression 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 48 psig is consistent with the accident analyses and the maximum preoperational leak rate test pressure. It is expected that the majority of the leakage from valves, penetrations, and seals would be into the reactor building. However, it is possible that leakage into other parts of the facility could occur. Such leakage paths that may affect significantly the consequences of accidents are to be minimized. The personnel air lock is tested at 10 psig because the inboard door is not designed to shut in the opposite direction.

The results of the loss-of-coolant accident analysis referenced in Section 5.2.4.3 of the SAR indicate that fission products would not be released directly to the environs because of leakage from the main steamline isolation valves due to holdup in the steam system complex. Although this effect would indicate that an adequate margin exists with regard to the release of fission products, a program will be undertaken to further reduce the potential for such leakage to bypass the standby gas treatment system.

Surveillance of the reactor building-pressure suppression chamber vacuum breakers consists of operability checks and leakage tests (conducted as part of the containment leaktightness tests). These vacuum breakers are normally in the closed position and open only during tests or an accident condition. As a result, a testing frequency of 3 months for operability is considered justified for this equipment. Inspections and calibrations are performed during refueling outages, this frequency being based on experience and judgment.

Pressure suppression chamber-drywell vacuum breakers monthly operability tests are performed to check the capability of the disks to open and close and to verify that the position indication and alarm circuits function properly. The disks must open during accident conditions and during transient additions of energy through relief valves. This periodic operation of the disks and the quality of equipment justify the frequency of operability tests of this equipment.

Following each quarterly operability test, a differential pressure decay rate test is performed to verify that leakage from the drywell to the suppression chamber is within specified limits.

Measurement of force to open, calibration of position switches, inspection of equipment, and functional testing are performed during each refueling outage. This frequency is based on equipment quality, experience, and judgment. Also, a more stringent differential pressure decay rate test is performed during refueling outages than is performed monthly. This test is performed to verify that total leakage paths between the drywell and suppression chamber are not in excess of the equivalent to a 1-inch orifice.

This small leakage path is only a small fraction of the allowable, thus integrity of the containment system is assured prior to startup following each refueling outage (Reference 1).

When a suppression chamber-drywell vacuum breaker valve is exercised through an opening-closing cycle, the position-indicating lights at the remote test panel are designed to function as follows:

Full closed (closed to ≤ 1/16 inch open)	2 Green - On 2 Red - Off
Intermediate position (≥ 1/16 inch open to < full open)	2 Green - On 2 Red - On
Full open	2 Green - Off 2 Red - On

The remote test panel consists of a push button to actuate the air cylinder for testing, two red lights, and two green lights for each of the twelve valves. The two switches controlling the red lights are adjusted to provide indication and alarm if a disk opening occurs that is equivalent to 1/16 inch at all points around the circumference of the valve disk. The physical characteristics of the valve and the positioning of the limit switches permit one setting of the limit switches to satisfy the criteria. The two switches controlling the green lights are adjusted to provide indication of the disk very near the full open position. The control room alarm circuits for each vacuum breaker are redundant and fail safe. This assures that no single failure will defeat alarming the control room when a valve is open beyond allowable and when power to the switches fails. The alarm is needed to alert the operator that action must be taken to correct a malfunction or that system degradation has occurred and additional testing is required immediately. The frequency of testing the alarms is based on experience and quality of the equipment.

B. Standby Gas Treatment System

See Specification 4.7.B.

C. Secondary Containment

Initiating reactor building isolation and operation of the standby gas treatment system to maintain at least 1/4 inch of water vacuum within the secondary containment provides an adequate test of the operation of the reactor building isolation valves, leaktightness of the reactor building, and performance of the standby gas treatment system. Functionally testing the initiating sensors and associated trip channels demonstrates the capability of automatic actuation. Performing these tests prior to refueling will demonstrate secondary containment capability prior to the time the primary containment is opened for refueling. Periodic testing gives sufficient confidence of reactor building integrity and standby gas treatment system performance capability.

(The frequency of tests and sample analysis is necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Standby gas treatment system in-place testing procedures will be established utilizing applicable sections of ANSI N510-1975 standard as a procedural guideline only. Operation of the standby gas treatment system every month for 10 hours will reduce the moisture buildup on the adsorbent. If painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals, or foreign materials, the same tests and sample analysis should be performed as required for operational use. Replacement adsorbent should be qualified according to the guidelines of Regulatory Guide 1.52 Revision 1 (June 1976). The charcoal adsorber efficiency test procedures will allow for the removal of one representative sample cartridge and testing in accordance with the guidelines of Table 3 of Regulatory Guide 1.52 Revision 1 (June 1976). The sample will be at least 2 inches in diameter and a length equal to the thickness of the bed. If the iodine removal efficiency test results are unacceptable, all adsorbent in the system will be replaced. High-efficiency particulate filters are installed before and after the charcoal filters to prevent clogging of the carbon adsorbers and to minimize potential release of particulates to the environment. 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 in-place testing with DOP as the testing medium. Any HEPA filters found defective will be replaced with filters qualified pursuant to regulatory guide position C.3.d. of Regulatory Guide 1.52 Revision 1 (June 1976). Once per operating cycle demonstration of HEPA filter pressure drop, operability of inlet heaters at rated power, air distribution to each HEPA filter, and automatic initiation of each standby gas treatment system circuit is necessary to assure system performance capability). Note: bases within parentheses will not be applicable until about December 31, 1976, when equipment modifications are completed to allow increased testing.

D. Primary Containment Isolation Valves

Those large pipes comprising a portion of the reactor coolant system, whose failure could result in uncovering the reactor core, are supplied with automatic isolation valves (except those lines needed for emergency core cooling system operation or containment cooling). The closure times specified herein are adequate to prevent loss of more coolant from the circumferential rupture of any of these lines outside the containment than from a steamline rupture. Therefore, this isolation valve closure time is sufficient to prevent uncovering the core.

In order to assure that the doses that may result from a steamline break do no exceed the 10 CFR 100 guidelines, it is necessary that no fuel rod perforation resulting from the accident occur prior to closure of the main steam line isolation valves. Analyses indicate that fuel rod cladding perforations would be avoided for main steam valve closure times, including instrument delay, as long as 10.5 seconds. However, for added margin, the technical specifications require a valve close time of not greater than 5 seconds.

For reactor coolant system temperature less than 212°F, the containment could not become pressurized due to a loss-of-coolant accident. The 212°F limit is based on preventing pressurization of the reactor building and rupture of the blowout panels. These valves are highly reliable, have low service requirement, and most are normally closed. The initiating sensors and associated trip channels are also checked to demonstrate the capability for automatic isolation (reference SAR Section 5.2.2 and Table 5.2.4).

The test interval at once per operating cycle for automatic initiation results in a failure probability of 1.1×10^{-7} that a line will not isolate. More frequent testing for valve operability results in a more reliable system.

The containment is penetrated by a large number of small diameter instrument lines which contact the primary coolant system. A program for periodic testing and examination of the flow check valves in these lines is performed by blowing down the instrument line during a vessel hydro and observing the following conditions, which will verify that the flow check valve is operable:

1. a distinctive 'click' when the poppet valve seats, and

2. an instrumentation high flow that quickly reduces to a slight trickle.

References

1. Quad-Cities Special Report Number 4.

2. R.E. Adams and W.E. Browning, Jr., ORNL 3726, 'Iodine Vapor Adsorption Studies for the NS Savannah' Project, February, 1965.

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION

Isolation Group	Valve Identification	Valve Number for Units 1 and 2	Number of Power-Operated Valves Inboard	Outboard	Maximum Operating Time (sec)	Normal Operating Position	Action on Initiating Signal
	Main Steam Isolation						
1	Main steam isolation valve	AO-203-1A, 1B, 1C, 1D	4		$3 \leq T < 5$	O	GC
1	Main steam isolation valve	AO-203-2A 2B, 2C, 2D		4	$3 \leq T < 5$	O	GC
1	Main steam drain isolation valve	MO-220-1	1		≤ 35	C	SC
1	Main steam drain isolation valve	MO-220-2		1	≤ 35	C	SC
	Sampling						
1	Recirculating sample valve	AO-220-44	1		≤ 5	O	GC
1	Recirculation sample valve (NOTE: Valve can be reopened after isolation for sampling)	AO-220-45		1	≤ 5	O	GC
	RHR						
2	RHR discharge to radwaste	MO-1001-20	1		≤ 25	C	SC
2	RHR discharge to radwaste	MO-1001-21		1	≤ 25	C	SC

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION

Isolation Group	Valve Identification	Valve Number for Units 1 and 2	Number of Power-Operated Valves Inboard	Outboard	Maximum Operating Time (sec)	Normal Operating Position	Action on Initiating Signal
2	Reactor shutdown cooling supply	MO-1001-47		1	≤40	C	SC
2	Reactor shutdown cooling supply	MO-1001-50	1		≤40	C	SC
2	Reactor head spray	MO-1001-60		1	≤25	C	SC
2	Reactor head spray	MO-1001-63	1		≤25	C	SC
	Pressure Suppression						
2	Drywell purge valve	AO-1601-21	1		≤10	C	SC
2	Vent valve	AO-1601-22		1	≤10	C	SC
2	Drywell vent valve	AO-1601-23	1		≤10	C	SC
2	Vent to reactor building exhaust system	AO-1601-24		1	≤10	C	SC
2	Nitrogen purge	AO-1601-55		1	≤10	O	GC
2	Torus purge valve	AO-1601-56	1		≤10	O	GC
2	Makeup valve	MO-1601-57	1		≤15	O	GC
2	Torus makeup valve	AO-1601-58		1	≤15	C	SC

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION

Isolation Group	Valve Identification	Valve Number for Units 1 and 2	Number of Power-Operated Valves Inboard	Outboard	Maximum Operating Time (sec)	Normal Operating Position	Action on Initiating Signal
2	Drywell makeup valve	AO-1601-59		1	≤15	O	GC
2	Torus vent valve	AO-1601-60	1		≤10	C	SC
2	Torus 2-inch vent relief	AO-1601-61	1		≤15	C	SC
2	Drywell 2-inch vent relief	AO-1601-62	1		≤15	C	SC
2	Vent to SGT system	AO-1601-63		1	≤10	C	SC
2	Drywell pneumatic Supply isolation	AO-4720 AO-4721		2	≤10	O	GC
	Radwaste						
2	Drywell floor drain discharge	AO-2001-3	1		≤20	O	GC
2	Drywell floor drain discharge	AO-2001-4		1	≤20	O	GC
2	Drywell equipment drain discharge	AO-2001-15	1		≤20	O	GC
2	Drywell equipment drain discharge (NOTE: Valve can be reopened after isolation for sampling)	AO-2001-16		1	≤20	O	GC

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION

Isolation Group	Valve Identification	Valve Number for Units 1 and 2	Number of Power-Operated Valves Inboard	Outboard	Maximum Operating Time (sec)	Normal Operating Position	Action on Initiating Signal
	Oxygen Analyzer						
2	Oxygen analyzer valve	AO-8801-A, B, C, D	4		≤10	O	GC
2	Oxygen analyzer valve	AO-8802-A, B, C, D		4	≤10	O	GC
2	Oxygen analyzer valve	AO-8803A	1		≤10	O	GC
2	Oxygen analyzer valve	AO-8803B		1	≤10	O	GC
	Traversing Incore Probe						
2	On isolation signal, the TIP detector is withdrawn if in use; five ball valves and one nitrogen purge are closed.	TIP Ball Valve 700-733 TIP Purge Valve Assembly 700-743					

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION

Isolation Group	Valve Identification	Valve Number for Units 1 and 2	Number of Power-Operated Valves Inboard	Outboard	Maximum Operating Time (sec)	Normal Operating Position	Action on Initiating Signal
	Reactor Water Cleanup						
3	Pump suction isolation valve	MO-1201-2	1		≤30	O	GC
3	Pump suction isolation valve	MO-1201-5		1	≤30	O	GC
	HPCI						
4	Steam isolation valve	MO-2301-4	1		≤50	O	GC
4	Steam isolation valve	MO-2301-5		1	≤50	O	GC
	RCIC						
5	Turbine steam supply	MO-1301-16	1		≤25	O	GC
5	Turbine steam supply	MO-1301-17		1	≤25	O	GC

TABLE 3.7-1 (Cont'd)

Key:
- O: open
- C: closed
- SC: stays closed
- GC: goes closed

Note: Isolation groupings are as follows:

Group 1: The valves in Group 1 are closed upon any one of the following conditions:
1. Reactor low-low-water level
2. Main steamline high radiation
3. Main steamline high flow
4. Main steamline tunnel high temperature
5. Main steamline low pressure

Group 2: The actions in Group 2 are initiated by any one of the following conditions:
1. Reactor low water level
2. High drywell pressure

Group 3: Reactor low water level alone initiates the following:
1. Cleanup demineralizer system isolation

Group 4: Isolation valves in the high pressure coolant injection system (HPCI) are closed upon any one of the following signals:
1. HPCI steamline high flow
2. High temperature in the vicinity of the HPCI steamline
3. Low reactor pressure

Group 5: Same as Group 4 except applies to RCIC

TABLE 3.7-2

PRIMARY CONTAINMENT LEAKAGE TEST PENETRATIONS

Double-Gasketed Seals

X-1	Equipment hatch
X-2	Personnel air lock
X-6	Control rod drive hatch
X-35A through G	TIP drives
X-4	Drywell head access hatch
X-200A & B	Suppression chamber access hatch
1 through 8	Drywell head shear lug (inspection hatch)

Pipe Penetrations

X-7A through D	Main steam
X-8	Main steamline drain
X-9A & B	Feedwater
X-10	Reactor core isolation cooling
X-11	High-pressure coolant injection
X-12	Residual heat removal
X-13A & B	Residual heat removal
X-14	Reactor coolant cleanup
X-16A & B	Core spray
X-17	Reactor vessel head spray
X-23 & 24	Reactor building closed cooling water
X-25 & 26	Drywell ventilation
X-36	Control rod drive return
X-47	Standby liquid control

Electrical Penetrations

X-100B, C, E, F, & G
X-101A, B & D
X-102B
X-103
X-104A through D & F
X-105C
X-106A & B
X-107A & B

3.8/4.8 RADIOACTIVE EFFLUENTS

Limiting Conditions for Operation

Applicability:

Applies to the radioactive effluents from the plant.

Surveillance Requirements

Applicability:

Applies to the periodic measurements of radioactive effluents.

Specifications

A Gaseous Effluents

1. The dose rate in unrestricted areas (at or beyond the site boundary, Figure 4.8-1) due to radioactive materials released in gaseous effluents from the site shall be limited to the following:

   a. For Noble Gases:

      (1) Less than 500 mrem/ year to the whole body.

      (2) Less than 3000 mrem/ year to the skin.

   b. For iodine-131, for iodine-133, and for all radionuclides in particulate form with half-lives greater than 8 days less than 1500 mrem/year.

A. Gaseous Effluents

1. The dose rates due to radioactive materials released in gaseous effluents from the site shall be determined to be within the prescribed limits by obtaining representative samples in accordance with the sampling and analysis program specified in Table 4.8-1. The dose rates are calculated using methods prescribed in the Off-Site Dose Calculation Manual (ODCM).

c. If the dose rates exceed the above limits, without delay decrease the release rates to bring the dose rates within the limits, and provide prompt notification to the Commission (6.6.B.1)

2. The air dose in unrestricted areas (at or beyond the site boundary) due to Noble Gases released in gaseous effluents from the unit shall be limited to the following:

a. For gamma radiation:

(1) Less than or equal to 5 mrad during any calendar quarter.

(2) Less than or equal to 10 mrad during any calendar year.

b. For Beta radiation:

(1) Less than or equal to 10 mrad during any calendar quarter.

(2) Less than or equal to 20 mrad during any calendar year.

2. The air dose due to releases of radioactive noble gases in gaseous effluents shall be determined to be within the prescribed limits by obtaining representative samples in accordance with the sampling and analysis program specified in sections A and B of Table 4.8-1. The allocation of effluents between units having shared effluent control systems and the air doses are determined using methods prescribed in the ODCM at least once every 31 days.

c. With the calculated air dose from radioactive noble gases in gaseous effluents exceeding any of the above limits, prepare and submit to the Commission within 30 days, a Special Report which identifies the cause(s) for exceeding the limit(s) and defines the corrective actions to be taken to ensure that future releases are in compliance with 3.8.A.2.a & b. This is in lieu of a Licensee Event Report.

d. With the calculated air dose from radioactive noble gases in gaseous effluents exceeding the limits of Specification 3.8.A.2.a. or 3.8.A.2.b., prepare and submit a Special Report to the Commission within 30 days and limit the subsequent releases such that the doses or dose commitment to a member of the public from all uranium fuel cycle sources is limited to less than or equal to 25 mrem to the total body or any organ (except thyroid, which is limited to less than or equal to 75 mrem) over 12 consecutive months. This Special Report shall include an analysis which demonstrates that radiation exposure to all members of the public from all uranium fuel cycle sources (including all effluent pathways and direct radiation) are

less than the 40 CFR Part 190 Standard. Otherwise, obtain a variance from the Commission to permit releases which exceed the 40 CFR Part 190 Standard. The radiation exposure analysis contained in the Special Report shall use the methods prescribed in the ODCM. This report is in lieu of a Licensee Event Report.

3. The dose to a member of the public in unrestricted areas (at or beyond the site boundary) from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from the unit shall be limited to the following:

3. The dose to a member of the public due to releases of iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days shall be determined to be within the prescribed limits by obtaining representative samples in accordance with the sampling and analysis program specified in Table 4.8-1.

For radionuclides not determined in each batch or weekly composite, the dose contribution to the current calendar quarter cumulative summation may be estimated by assuming an average monthly concentration based on the previous monthly or quarterly composite analyses. However, for reporting purposes, the calculated dose contributions shall be based on the actual composite analyses when possible.

The allocation of effluents between units having shared effluent control systems and the doses are determined using the methods prescribed in the ODCM at least once every 31 days.

a. Less than or equal to 7.5 mrem to any organ during any calendar quarter.

b. Less than or equal to 15 mrem to any organ during any calendar year.

c. With the calculated dose from the release of iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents exceeding any of the above limits, prepare and submit to the Commission within 30 days, a Special Report which identifies the cause(s) for exceeding the limit and defines the corrective actions taken and the proposed actions to be taken to ensure that future releases are in compliance with 3.8.A.3. a. & b. This is in lieu of a Licensee Event Report.

d. With the calculated dose from the release of iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents exceeding the limits of Specification 3.8.A.3.a. or 3.8.A.3.b., prepare and submit a Special Report to the Commission within 30 days and limit subsequent releases such that the dose or dose commitment to a member of the public from

all uranium fuel cycle sources is limited to less than or equal to 25 mrem to the total body or organ (except the thyroid, which is limited to less than or equal to 75 mrem) over 12 consecutive months. This Special Report shall include an analysis which demonstrates that radiation exposures to all members of the public from all uranium fuel cycle sources (including all effluent pathways and direct radiation) are less than the 40 CFR Part 190 Standard. Otherwise, obtain a variance from the Commission to permit releases which exceed the 40 CFR Part 190 Standard. The radiation exposure analysis contained in the Special Report shall use the methods prescribed in the ODCM. This report is in lieu of a Licensee Event Report.

4. Off-Gas System

a. At all times during processing for discharge to the environs, process and control equipment provided to reduce the amount or concentration of radioactive materials shall be operated.

b. The above specification shall not apply for the Off-Gas Charcoal Adsorber Beds below 30 percent of rated thermal power.

4. Off-Gas System

Doses due to treated gases released to unrestricted areas at or beyond the site boundary shall be projected at least once per 31 days in accordance with the ODCM.

5. Explosive Gas Mixture

   a. The concentration of hydrogen in the off-gas hold up system, downstream of the recombiner shall be limited by having a recombiner operable within the allowable band of the base-line plot of recombiner outlet temperature vs. reactor power, whenever the reactor is operating at a pressure greater than 900 psig.

   b. The recombiner may be inoperable for 48 hours.

6. With either the recombiners inoperable, or all charcoal beds bypassed for more than 7 days in a calendar quarter while operating above 30 percent of rated thermal power, prepare and submit to the Commission within 30 days a special report which includes the following information:

   a. Identification of the defective equipment.

   b. Cause of the defective equipment.

   c. Action(s) taken to restore the equipment to an operating status.

   d. Length of time the above requirements were not satisfied.

5. Explosive Gas Mixture

   Once per 8 hours verification will be made that the unit is operating within the allowable band of the base-line plot of recombiner outlet temperature vs. reactor power.

e. Volume and curie content of the waste discharged which was not processed by the inoperable equipment but which required processing.

f. Action(s) taken to prevent a recurrence of equipment failures.

This is in lieu of a Licensee Event Report.

7. The release rate of the sum of the activities from the noble gases measured at the main condenser air ejector shall be limited to less than or equal to 100 microcuries/sec per MWt (after 30 minutes decay) at all times. With the release rate of the sum of the activities from noble gases at the main condenser air ejector exceeding 100 microcuries/sec per MWt (after 30 minutes decay), restore the release rate to within its limits within 72 hours, or be in at least HOT STANDBY within the next 12 hours.

7. The radioactivity rate of noble gases at (near) the outlet of the main condenser air ejector shall be continuously monitored in accordance with Specification 3.2.H. The release rate of the sum of the activities from noble gases from the main condenser air ejector shall be determined to be within the limits of Specification 3.8.A.7. at the following frequencies by performing an isotope analysis of a representative sample of gases taken at the recombiner outlet, or at the air ejector outlet if the recombiner is bypassed.

a. At least once per 31 days.

b. Within 4 hours following an increase, as indicated by the main condenser air ejector noble gas activity monitor, of greater than 50%, after factoring out increases due to changes in thermal power level and off-gas flow, in the nominal steady-state fission gas release from the primary coolant.

B. Liquid Effluents

1. The concentration of radioactive material released from the site to unrestricted areas (at or beyond the site boundary, figure 4.8-1) shall be limited to the concentrations specified in 10 CFR Part 20, Appendix B, Table 11, Column 2 with the Table 4.8-2 values representing the MPC's for noble gases.

   With the concentration of radioactive material released from the site to unrestricted areas exceeding the above limits, without delay decrease the release rate of radioactive materials and/or increase the dilution flow rate to restore the concentration to within the above limits.

2. The dose or dose commitment above background to a member of the public from radioactive materials in liquid effluents released to unrestricted areas (at or beyond the site boundary) from the site shall be limited to the following:

   a. During any calendar quarter:

      (1) Less than or equal to 3 mrem to the whole body.

      (2) Less than or equal to 10 mrem to any organ.

B. Liquid Effluents

1. The concentration of radioactive material in unrestricted areas shall be determined to be within the prescribed limits by obtaining the representative samples in accordance with the sampling and analysis program specified in Table 4.8-3. The sample analysis results will be used with the calculational methods in the ODCM to determine that the concentrations are within the limits of Specification 3.8.B.1.

2. a. The dose contributions from measured quantities of radioactive material shall be determined by calculation at least once per 31 days and a cumulative summation of these total body and organ doses shall be maintained for each calendar quarter.

b. During any calendar year:

(1) Less than or equal to 6 mrem to the whole body.

(2) Less than or equal to 20 mrem to any organ.

c. With the calculated dose from the release of radioactive materials in liquid effluents exceeding any of the above limits, prepare and submit to the Commission within 30 days a Special Report which identifies the cause(s) for exceeding the limit(s) and defines the corrective actions taken and the proposed actions to be taken to ensure that future releases are in compliance with 3.8.B.2.a. & b. This is in lieu of a Licensee Event Report.

d. With the calculated dose from the release of radioactive materials in liquid effluents exceeding the limits of Specification 3.8.B.2.a. or 3.8.B.2.b., prepare and submit a Special Report to the Commission within 30 days and limit the subsequent releases such that the dose or dose commitment to a member of the public from all

b. Doses computed at the nearest community water system will consider only the drinking water pathway and shall be projected using the methods prescribed in the ODCM at least once per 92 days.

uranium fuel cycle sources is limited to less than or equal to 25 mrem to the total body or any organ (except thyroid, which is limited to less than or equal to 75 mrem) over 12 consecutive months. This Special Report shall include an analysis which demonstrates that radiation exposures to all members of the public from all uranium fuel cycle sources (including all effluent pathways and direct radiation) are less than the 40 CFR Part 190 Standard. Otherwise obtain a variance from the Commission to permit releases which exceed the 40 CFR Part 190 Standard. The radiation exposure analysis contained in the Special Report shall use methods prescribed in the ODCM. This report is in lieu of a Licensee Event Report.

e. With the projected annual whole body or any internal organ dose computed at the nearest downstream community water system is equal to or exceeds 2 mrem from all radioactive materials released in liquid effluents from the Station, prepare and submit a Special Report within 30 days to the operator of the community water system. The

report is prepared to assist the operator in meeting the requirements of 40 CFR 141: EPA Primary Drinking Water Standards. A copy of this report will be sent to the NRC. This is in lieu of a Licensee Event Report.

3. At all times during processing prior to discharge to the environs, process and control equipment provided to reduce the amount or concentration of radioactive materials shall be operated when the projected dose due to liquid effluent releases to unrestricted areas (see Figure 4.8-1), when averaged over 31 days, exceeds 0.13 mrem to the total body or 0.42 mrem to any organ.

4. If liquid waste has to be or is being discharged without treatment as required above, prepare and submit to the Commission within 30 days, a report which includes the following information:

   a. Identification of the defective equipment.

   b. Cause of the defective equipment.

   c. Action(s) taken to restore the equipment to an operating status.

   d. Length of time the above requirements were not satisfied.

3. Liquid Waste Treatment

   a. Doses due to liquid releases to unrestricted areas (at or beyond the site boundary) shall be projected at least once per 31 days in accordance with the ODCM.

e. Volume and curie content of the waste discharged which was not processed by the appropriate equipment but which required processing.

f. Action(s) taken to prevent a recurrence of equipment failures.

This is in lieu of a Licensee Event Report.

C. Mechanical Vacuum Pump

1. The mechanical vacuum pump shall be capable of being isolated and secured on a signal of main steam high radiation or shall be isolated and secured whenever the main steam isolation valves are open.

D. Environmental Monitoring Program

1. The environmental monitoring program given in Table 4.8-4 shall be conducted except as specified below.

2. With the radiological environmental monitoring program not being conducted as specified in Table 4.8-4, prepare and submit to the Commission, in the Annual Radiological Operating Report, a

C. Mechanical Vacuum Pump

At least once during each operating cycle, automatic securing and isolation of the mechanical vacuum pump shall be verified.

D. Environmental Monitoring Program

1. The radiological environmental monitoring samples shall be collected pursuant to Table 4.8-4 from the locations specified in the ODCM, and shall be analyzed pursuant to the requirements of Table 4.8-6.

2. The results of analyses performed on radiological environmental monitoring samples shall be summarized in the Annual Radiological Environmental Operating Report.

description of the reasons for not conducting the program as required and the plans for preventing a recurrence. Deviations are permitted from the required sampling schedule if specimens are unobtainable due to hazardous conditions, seasonal unavailability, contractor omission which is corrected as soon as discovered, malfunction of sampling equipment, or if a person who participates in the program goes out of business. If the equipment malfunctions, corrective actions shall be completed as soon as practical. If a person supplying samples goes out of business, a replacement will be found as soon as possible. All deviations from the sampling schedule shall be described in the annual report.

3. With the level of radioactivity in an environmental sampling medium at one or more of the locations specified in the ODCM exceeding the limits of Table 4.8-5 when averaged over any calendar quarter, prepare and submit to the Commission within 30 days from the end of the affected calendar quarter, a Special Report which includes an evaluation of any release conditions, environmental factors or other aspects which caused the limits of Table 4.8-5 to be exceeded. This report is not required if the measured level of radioactivity was not the result of plant effluents; however, in such an event the condition shall be reported and described in the Annual Radiological Environmental Operating Report.

3. The land use census shall be conducted at least once per twelve months between the dates of June 1 and October 1 by a door-to-door survey, aerial survey, road survey, or by consulting local agriculture authorities.

4. With milk samples unavailable from one or more of the sample locations required by Table 4.8-4, identify locations for obtaining replacement samples and add them to the radiological environmental monitoring program within 30 days. The locations from which samples were unavailable may then be deleted from the monitoring program. In lieu of a Licensee Event Report, identify the cause of the unavailability of samples and identify the new location(s) for obtaining replacement samples in the Annual Radiological Environmental Operating Report and also include in the report a revised figure(s) and table for the ODCM reflecting the new location(s).

4. The results of the land use census shall be included in the Annual Radiological Environmental Operating Report.

5. A census of nearest residences and of animals producing milk for human consumption shall be conducted annually (during the grazing season for animals) to determine their location and number with respect to the site. The nearest residence in each of the 16 meteorological sectors shall also be determined within a distance of five miles. The census shall be conducted under the following conditions:

   a. Within a 2-mile radius from the plant site, enumeration of animals and nearest residences by a door-to-door or equivalent counting technique.

5. The results of the analyses performed as part of the required crosscheck program shall be included in the Annual Radiological Environmental Operating Report. The analyses shall be done in accordance with the ODCM.

b. Within a 5-mile radius, enumeration of animals by using referenced information from county agricultural agents or other reliable sources

6. With a land use census identifying location(s) of animals which yield(s)an ODCM calculated dose or dose commitment greater than the values currently being calculated in Specification 4.8.A.3, the new location(s) shall be added to the radiological environmental monitoring program within 30 days, if possible.

   The sampling location, having the lowest calculated dose or dose commitment (via the same exposure pathway) may be deleted from this monitoring program after October 31 of the year in which this land use census was conducted.

7. Radiological analyses shall be performed on samples representative of those in Table 4.8-4, supplied as a part of the Interlaboratory Comparison Program which has been approved by the NRC.

8. With analyses not being performed as required, report the corrective actions taken to prevent a recurrence to the Commission in the Annual Radiological Environmental Operating Report.

E. Solid Radioactive Waste

1. The solid radwaste system shall be used as applicable in accordance with the PCP to process wet radioactive wastes to meet shipping and burial ground requirements.

2. With the provisions of the Process Control Program not satisfied, suspend shipments of defectively processed or defectively packaged solid radioactive waste from the site.

E. Solid Radioactive Waste

1. The PCP shall specify the method and frequency to verify solidification of radioactive waste. Actions to be taken if solidification is not verified shall also be specified in the PCP.

F. Miscellaneous Radioactive Materials Sources

Source Leakage Test

Specification

Each sealed source containing radioactive material in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material shall be free of $\geq$ 0.005 microcuries of removable contamination.

Each sealed source with removable contamination in excess of the above limit shall be immediately withdrawn from use and either decontaminated and repaired or disposed of in accordance with Commission Regulations.

A complete inventory of radioactive materials in the licensee's possession shall be maintained current at all times.

F. Miscellaneous Radioactive Materials Sources

Each sealed source shall be tested for leakage and/or contamination by the licensee or by other persons specifically authorized by the Commission or an Agreement state. The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

Each category of sealed sources shall be tested at the frequency described below:

1. Sources in use (<u>excluding start-up previously subjected to core flux</u>) - At least once per 6 months for all sealed sources containing radioactive material:

   a. With a half-life greater than 30 days (excluding Hydrogen 3), and

   b. In any form other than gas.

2. Stored sources not in use - Each sealed source shall be tested prior to the use or transfer to another licensee unless tested within the previous 6 months. Sealed sources transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.6.C.3 if source leakage tests reveal the presence of $\geq$ 0.005 microcuries of removable contamination.

G. In the event a limiting condition for operation and/or associated action requirements identified in sections 3.8.A. through 3.8.E., and 4.8.A. through 4.8.E. cannot be satisfied because of circumstances in excess of those addressed in the specifications, no changes are required in the operational condition of the plant, and this does not prevent the plant from entry into an operational mode.

H. Control Room Emergency Filtration System

1. The control room emergency filtration system, including at least one booster fan shall be operable at all times when secondary containment integrity is required, except as specified in Sections 3.8.H.1.a. and b.

H. Control Room Emergency Filtration System

1. At least once per month, initiate 2000 cfm ($\pm$ 10%) flow through the control room emergency filtration system for at least 10 hours with the heaters operable.

a. After the control room emergency filtration system is made or found to be inoperable for any reason, reactor operation and fuel handling are permissible only during the succeeding 14 days. Within 36 hours following the 14 days, the reactor shall be placed in a condition for which the control room emergency filtration system is not required in accordance with Specification 3.7.C.1.a. through d.

b. Specification 3.8.H.1.a. above does not apply during performance or post-maintenance testing, or during removal of the charcoal test canister.

2. Periodic Performance Requirements

a. The results of the in-place DOP tests at 2000 cfm (± 10%) on HEPA filters shall show ≤ 1% DOP penetration.

2. Performance Requirement Tests

a. At least once per operating cycle but not to exceed 18 months, or following painting, fire, or toxic chemical release in any ventilation zone communicating with the intake of the system while the system is operating that could contaminate the HEPA filters of charcoal adsorbers, perform the following:

1) In-place DOP test the HEPA filter banks to verify leaktight integrity.

2) In-place test the charcoal adsorber banks with halogenated hydrocarbon tracer to verify leaktight integrity.

3) Remove one carbon test canister from the charcoal adsorber. Subject this sample to a laboratory analysis to verify methyl iodide removal efficiency.

b. The results of in-place halogenated hydrocarbon tests at 2000 cfm (± 10%) on the charcoal banks shall show ≤ 1% penetration.

b. At least once per operating cycle, but not to exceed 18 months, the following conditions shall be demonstrated:

1) Pressure drop across the combined filters is less than 6 inches of water at 2000 cfm (± 10%) flow rate.

2) Operability of inlet heater demonstrates heater ΔT of 15°F.

c. The results of laboratory carbon sample analysis shall show ≥ 90% methyl iodide removal efficiency when tested at 130°C and 95% R.H.

3. Postmaintenance Requirements

a. After any maintenance or heating that could affect the HEPA filter or HEPA filter mounting frame leak-tight integrity, the results of the in-place DOP tests at 2000 cfm (± 10%) on HEPA filters shall show ≤ 1% DOP penetration.

3. Postmaintenance Testing

a. After any maintenance or testing that could affect the leaktight integrity of the HEPA filters, perform in-place DOP tests on the HEPA filters in accordance with Specification 3.8.H.2.a.

b. After any maintenance or testing that could affect the charcoal adsorber leaktight integrity, the results of in-place halogenated hydrocarbon tests at 2000 cfm (± 10%) shall show ≤ 1% penetration.

b. After any maintenance or testing that could affect the leaktight integrity of the charcoal adsorber banks, perform halogenated hydrocarbon tests on the charcoal adsorbers in accordance with Specification 3.8.H.2.b.

3.8/4.8.A Limiting Conditions for Operation and Surveillance Requirement Bases

3.8/4.8.A.1 GASEOUS EFFLUENTS - DOSE

This specification is provided to ensure that the dose at the unrestricted area boundary from gaseous effluents from the units on the site will be within the annual dose limits of 10 CFR Part 20 for unrestricted areas. The annual dose limits are the doses associated with the concentrations of 10 CFR Part 20, Appendix B, Table II. These limits provide reasonable assurance that radioactive material discharged in gaseous effluents will not result in the exposure of an individual in an unrestricted area to annual average concentrations exceeding the limits specified in Appendix B, Table II of 10 CFR Part 20 (10 CFR Part 20.106(b)). The specified release rate limits restrict, at all times, the corresponding gamma and beta dose rates above background to an individual at or beyond the unrestricted area boundary to less than or equal to 500 mrem/year to the total body or to not less than or equal to 3000 mrem/year to the skin. These release rate limits also restrict, at all times, the corresponding thyroid dose rate above background to an infant via the cow-milk-infant pathway to not less than or equal to 1500 mrem/year for the nearest cow to the plant. For purposes of calculating doses resulting from airborne releases the main chimney is considered to be an elevated release point, and the reactor vent stack is considered to be a mixed mode release point.

3.8/4.8.A.2 DOSE, NOBLE GASES

This specification is provided to implement the requirements of Sections II.B, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Condition for Operation implements the guides set forth in Section II.B of Appendix I. The statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in gaseous effluents will be kept "as low as is reasonably achievable." The Surveillance Requirements implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I is to be shown by calculational procedures based on models and data such that the actual exposure of an individual through the appropriate pathways is unlikely to be substantially underestimated. The dose calculations established in the ODCM for calculating the doses due to the actual release rates of radioactive noble gases in gaseous effluents will be consistent with the methodology provided in 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," Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water Cooled Reactors", Revision 1, July 1977. The ODCM equations provide for determining the air doses at the unrestricted boundary based upon the historical average atmospheric conditions. NUREG-0133 provides methods for dose calculations consistent with Regulatory Guides 1.109 and 1.111.

3.8/4.8.A.3 DOSE, RADIOIODINES, RADIOACTIVE MATERIAL IN PARTICULATE FORM AND RADIONUCLIDES OTHER THAN NOBLE GASES

This specification is provided to implement the requirements of Sections II.C, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Conditions for Operation are the guides set forth in Section II.C of Appendix I. The statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable." The ODCM calculational methods specified in the surveillance requirements implements the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data such that the actual exposure of an individual through appropriate pathways is unlikely to be substantially underestimated. The ODCM calculational methods approved by NRC for calculating the doses due to the actual release rates of the subject materia's are required to be consistent with the methodology provided in 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", Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," Revision 1, July 1977. These equations also provide for determining the actual doses based upon the historical average atmospheric conditions. The release rate specifications for radioiodines, radioactive material in particulate form and radionuclides other than noble gases are dependent on the existing radionuclide pathways to man, in the unrestricted area. The pathways which were examined in the development of these specifications were: 1) individual inhalation of airborne radionuclides, 2) deposition of radionuclides onto green leafy vegetation with subsequent consumption by man and 3) deposition onto grassy areas where milk animals graze with consumption of the milk by man.

3.8/4.8.A.4 GASEOUS WASTE TREATMENT

The OPERABILITY of the gaseous waste treatment which reduces amounts or concentrations of radioactive materials ensures that the system will be available for use whenever gaseous effluents require treatment prior to release to the environment. The requirement that the appropriate portions of this system be operable when specified provides reasonable assurance that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable". This specification implements the requirements of 10 CFR Part 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50, and design objective Section II.D of Appendix I to 10 CFR Part 50.

3.8/4.8.A.5 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the off gas system is minimized in conformance with the requirements of General Design Criteria 60 of Appendix A to 10 CFR Part 50.

LIQUID EFFLUENTS

3.8/4.8.B.1 CONCENTRATION

This specification is provided to ensure that the concentration of radioactive materials released in liquid waste effluents from the site to unrestricted areas will be less than the concentration levels specified in 10 CFR Part 20, Appendix B, Table II, column 2. The concentration limit for noble gases, MPC in air (submersion), was converted to an equivalent concentration in water using the International Commission on Radiological Protection (ICRP) Publication 2.

3.8/4.8.B.2 DOSE

This specification is provided to implement the requirements of Sections II.A, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Condition for Operation implements the guides set forth in Section II.A of Appendix I. The statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in liquid effluents will be kept "as low as is reasonably achievable". The dose calculations in the ODCM implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data such that the actual exposure of an individual through appropriate pathways is unlikely to be substantially underestimated. The equations specified in the ODCM for calculating the doses due to the actual release rates of radioactive materials in liquid effluents will be consistent with the methodology provided in 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", Revision 1, October 1977 and Regulatory Guide 1.113, "Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I", April 1977. NUREG-0113 provides methods for dose calculations consistent with Reg Guide 1.109 and 1.113.

3.8/4.8.B.3 LIQUID WASTE TREATMENT

The operability of the liquid radwaste treatment system ensures that this system will be available for use whenever liquid effluents require treatment prior to release to the environment. The requirement that the appropriate portions of this system be used when specified provides assurance that the releases of radioactive materials in liquid effluents will be kept "as low as is reasonably achievable". This specification implements the requirements of 10 CFR Part 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50 and design objective Section II.D of Appendix I to 10 CFR Part 50.

3.8/4.8.D.1 MONITORING PROGRAM

The radiological monitoring program required by this specification provides measurements of radiation and of radioactive materials in those exposure pathways and for those radionuclides, which lead to the highest potential radiation exposures of individuals resulting from the station operation. This monitoring program thereby supplements the radiological effluent monitoring program by verifying that the measurable concentrations of radioactive materials and levels of radiation are not higher than expected on the basis of the effluent measurements and modeling of the environmental exposure pathways. Program changes may be initiated based on operational experience.

The detection capabilities required by Table 4.8-6 are state-of-the-art for routine environmental measurements in industrial laboratories. The specified lower limits of detection for I-131 in water, milk and other food products correspond to approximately one-quarter of the Appendix I to 10 CFR Part 50 design objective dose-equivalent of 15 mrem/year for atmospheric releases and 10 mrem/year for liquid releases to the most sensitive organ and individual. They are based on the assumptions given in 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", October 1977, except the change for an infant consuming 330 liters/year of drinking water instead of 510 liters/year.

3.8/4.8.D.6 LAND USE CENSUS

This specification is provided to ensure that changes in the use of unrestricted areas are identified and that modifications to the monitoring program are made if required by the results of this census. This census satisfies the requirements of Section IV.B.3 of Appendix I to 10 CFR Part 50.

3.8/4.8.D.7 CROSSCHECK PROGRAM

The requirement for participation in the interlaboratory comparison crosscheck program is provided to ensure that independent checks on the precision and accuracy of the measurements of radioactive material in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring in order to demonstrate that the results are reasonably valid.

3.8/4.8.C MECHANICAL VACUUM PUMP

The purpose of isolating the mechanical vacuum line is to limit release of activity from the main condenser. During an accident, fission products would be transported from the reactor through the main steamline to the main condenser. The fission product radioactivity would be sensed by the main steamline radioactivity monitors which initiate isolation.

3.8/4.8.E SOLID RADIOACTIVE WASTE

The operability of the solid radioactive waste system ensures that the system will be available for use whenever solid radwastes require processing and packaging prior to being shipped off-site. This specification implements the requirements of 10 CFR 50.36a and General Design Criteria 60 of Appendix A to 10 CFR Part 50.

3.8/4.8.F MISCELLANEOUS RADIOACTIVE MATERIALS SOURCES

The objective of this specification is to assure that leakage from byproduct, source and special nuclear material sources does not exceed allowable limits. The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium.

3.8/4.8.H CONTROL ROOM AIR FILTRATION

The purpose of these specifications is to assure availability of the control room emergency air filtration unit that has been installed in response to NUREG-0737 Item III D.3.4. Operation of this unit is described in the "Control Room Habitability Study" for Quad-Cities Station which was submitted to the NRC in December 1981.

TABLE 4.3-1

RADIOACTIVE GASEOUS WASTE SAMPLING AND ANALYSIS PROGRAM

GASEOUS RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DETECTION (LLD) (μCi/ml)
A. Main Chimney Reactor Bldg. Vent Stack	M Grab Sample	M[b]	Principal Gamma Emitters[e]	1×10^{-4}
		M	Tritium	1×10^{-6}
B. All Release Types as Listed in A Above	Continuous[d]	W[c] Charcoal Sample	I-131	1×10^{-12}
			I-133	1×10^{-10}
	Continuous[d]	W[c] Particulate Sample	Principal Gamma Emitters[e] (I-131, others)	1×10^{-11}
	Continuous[d]	Q Composite Particulate Sample	Sr-89	1×10^{-11}
			Sr-90	1×10^{-11}
	Continuous[d]	M Composite Particulate Sample	Gross Alpha	1×10^{-11}
C. Main Chimney	Continuous[d]	Noble Gas Monitor	Noble Gases	1×10^{-6}
D. Reactor Bldg Vent Stack	Continuous[d]	Noble Gas Monitor	Noble Gases	1×10^{-4}

TABLE 4.8-1 (Continued)
TABLE NOTATION

a. The lower limit of detection (LLD) is defined in table notation A. of Table 4.8-6.

b. Sampling and analyses shall also be performed following shutdown, startup, or a thermal power change exceeding 20 percent of rated thermal power in 1 hour unless (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has not increased more than a factor of 5, and (2) the noble gas activity monitor shows that effluent activity has not increased by more than a factor of 3.

c. Samples shall be changed at least once per 7 days and the analyses completed within 48 hours after removal from the sampler. Sampling shall also be performed within 24 hours following each shutdown, startup, or thermal power level change exceeding 20% of rated thermal power in one hour. This requirement does not apply if (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has not increased more than a factor of 5, and (2) the noble gas activity monitor shows that effluent activity has not increased by more than a factor of 3. When samples collected for 24 hours are analyzed, the corresponding LLD's may be increased by a factor of 10.

d. The ratio of sample flow rate to the sampled stream flow rate shall be known.

The principal gamma emitters for which the LLD specification applies exclusively are the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138 for gaseous emissions, and Mn-54, Fe-59, Co-60, Zn-65, Co-58, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144 for particulate emissions. Other peaks which are measurable and identifiable by gamma ray spectrometry, together with the above nuclides, shall be also identified and reported when an actual analysis is performed on a sample. Nuclides which are below the LLD for the analyses shall not be reported as being present at the LLD level for that nuclide.

TABLE 4.8-2

MAXIMUM PERMISSIBLE CONCENTRATION OF DISSOLVED OR ENTRAINED NOBLE GASES RELEASED FROM THE SITE TO UNRESTRICTED AREAS IN LIQUID WASTE

NUCLIDE	MPC(μCi/ml)*
Kr-58m	2×10^{-4}
Kr-85	5×10^{-4}
Kr-87	4×10^{-5}
Kr-88	9×10^{-5}
Ar-41	7×10^{-5}
Xe-131m	7×10^{-4}
Xe-133m	5×10^{-4}
Xe-133	6×10^{-4}
Xe-135m	2×10^{-4}
Xe-135	2×10^{-4}

* Computed from Equation 20 of ICRP Publication 2 (1959), adjusted for infinite cloud submersion in water, and R = 0.01 rem/week, density = 1.0 g/cc and Pw/Pt = 1.0.

TABLE 4.8-3
RADIOACTIVE LIQUID WASTE SAMPLING
AND ANALYSIS PROGRAM

LIQUID RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DETECTION (LLD) (μCi/ml)
A. Batch Waste Release Tanks	Prior to Each Batch	Prior to Each Batch	Principal Gamma Emitters[e]	5×10^{-7}
			I-131	1×10^{-6}
	Prior to Each Batch	M Composite[b]	Gross Alpha	1×10^{-7}
			H-3	1×10^{-5}
	Prior to Each Batch	Q Composite[b]	Fe-55	1×10^{-6}
			Sr-89, Sr-90	5×10^{-8}
	Prior to One Batch/M	M	Dissolved & Entrained Gases[f] (Gamma Emitters)	1×10^{-5}
B. Plant Continuous Releases[d]	M[c] (Grab Sample)	M[c]	I-131	1×10^{-6}
			Principal Gamma Emitters[e]	5×10^{-7}
			Dissolved & Entrained Gases[f] (Gamma Emitters)	1×10^{-5}
			H-3	1×10^{-5}
			Gross Alpha	1×10^{-7}
	Q[c] (Grab Sample)	Q[c]	Sr-89, Sr-90	5×10^{-8}
			Fe-55	1×10^{-6}

TABLE 4.8-3 (Continued)
TABLE NOTATION

a. The LLD is defined in Notation A of Table 4.8-6.

b. A composite sample is one in which the quantity of liquid samples is proportional to the quantity of liquid waste discharged and in which the method of sampling employed results in a specimen which is representative of the liquids released.

c. If the alarm setpoint of the service water effluent monitor as determined in the ODCM is exceeded, the frequency of analysis shall be increased to daily until the condition no longer exists.

d. A batch release is the discharge of liquid wastes of a discrete volume. Prior to sampling for analyses, each batch shall be isolated and then thoroughly mixed to assure representative sampling. A continuous release is the discharge of liquid wastes of a nondiscrete volume; e.g., from a volume or system that has an input flow during the release.

e. The principal gamma emitters for which the LLD specification applies exclusively are the following radionuclides: Mn-54, Fe-59, Co-60, Zn-65, Co-58, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144. Other peaks which are measurable and identifiable by gamma ray spectrometry together with the above nuclides, shall be also identified and reported when the actual analysis is performed on a sample. Nuclides which are below the LLD for the analyses shall not be reported as being present at the LLD level for that nuclide.

f. The dissolved and entrained gases (gamma emitters) for which the LLD specification applies exclusively are the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138. Other dissolved and entrained gases (gamma emitters) which are measurable and identifiable by gamma-ray spectrometry, together with the above nuclides, shall also be identified and reported when an actual analysis is performed on a sample. Nuclides which are below the LLD for the analyses shall not be reported as being present at the LLD level for that nuclide.

TABLE 4.8-4
RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Minimum Number of Samples and Sample Locations*	Sampling and Collection Frequency	Type and Frequency of Analysis
1. AIRBORNE			
a. Particulates	16 locations	Continuous operation of sampler for a week	Gross beta and gamma isotopic as specified in ODCM.
b. Radioiodine	16 locations	Continuous operation of sampler for two weeks	I-131 as specified in ODCM.
2. DIRECT RADIATION	Forty Locations (Minimum of two TLDs per packet)	Quarterly	

*Sample locations are described in the ODCM.

TABLE 4.8-4 (Continued)
RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Minimum Number of Samples and Sample Locations*	Sampling and Collection Frequency	Type and Frequency of Analysis
3. WATERBORNE			
a. Public Water	2 Locations	Monthly composite of weekly collected samples	Gamma isotopic analysis of each composite sample
b. Sediment	1 down tream location in receiving body of water	Annually	Gamma isotopic analysis of each sample
c. Plant Cooling Water	Intake, Discharge	Weekly composite	Gross Beta analysis of each sample

*Sample locations are described in the ODCM.

TABLE 4.8-4 (Continued)
RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Minimum Number of Samples and Sample Locations*	Sampling and Collection Frequency	Type and Frequency of Analysis
4. INJESTION			
a. Milk	2 Locations	At least once weekly when ani-animals are on pasture; at least once per month at other times.	I-131 analysis of each sample
b. Fish	1 location in receiving body of water	Semi-annually	Gamma isotopic analysis on edible portions

*Sample locations are described in the ODCM

TABLE 4.8-5

REPORTING LEVELS FOR RADIOACTIVITY CONCENTRATIONS IN ENVIRONMENTAL SAMPLES

Reporting Levels

Analysis	Water	Airborne Particulate or Gases (pCi/m^3)	Fish (pCi/Kg, wet)	Milk (pCi/l)	Food Products (pCi/Kg, wet)
H-3	2×10^4(a)				
Mn-54	1×10^3		3×10^4		
Fe-59	4×10^2		1×10^4		
Co-58	1×10^3		3×10^4		
Co-60	3×10^2		1×10^4		
Zn-65	3×10^2		2×10^4		
Zr-Nb-95	4×10^2				
I-131	2	0.9		3	1×10^2
Cs-134	30	10	1×10^3	60	1×10^3
Cs-137	50	20	1×10^3	70	2×10^3
Ba-La-140	2×10^2			3×10^2	

a) for drinking water samples. This is 40 CFR Part 141 value.

TABLE 4.8-6

PRACTICAL LOWER LIMITS OF DETECTION (LLD)
FOR STANDARD ENVIRONMENTAL RADIOLOGICAL MONITORING PROGRAM

Sample Media	Analysis	LLD[A,B] (4.66 σ)	Units
Airborne "Particulate"	Gross Beta +	0.01	pCi/m^3
	Gamma Isotopic	0.01	pCi/m^3
Airborne I-131	Iodine 131	0.10	pCi/m^3
Milk/Public Water	I-131	5°	pCi/l
	Cs-134	10	pCi/l
	Cs-137	10 Δ	pCi/l
	Tritium	200	pCi/l
	Gross Beta +	5	pCi/l
	Gamma Isotopic	20	pCi/l/nuclide
Sediment	Gross Beta +	2	pCi/g dry
	Gamma Isotopic	0.2	pCi/g dry
Fish Tissue	I-131 - Thyroid	0.1	pCi/g wet
	Cs-134, 137	0.1	pCi/g wet
	Gross Beta +	1.0	pCi/g wet
	γ Isotopic	0.2	pCi/g wet

° 0.5 pCi/l on milk samples collected during the pasture season.

+ Referenced to Cs-137

Δ 5.0 pCi/l on milk samples

TABLE 4.8-6 (Continued)
TABLE NOTATION

A. The LLD is the smallest concentration of radioactive material in the sample that will be detected with 95 percent probability with only 5% probability of falsely concluding that a blank observation represents a "real" sequal.

For a particular measurement system (which may include radiochemical separation)

$$LLD = \frac{4.55 \cdot s_b}{A \cdot E \cdot V \cdot 2.22 \cdot Y \cdot \exp(-\lambda \Delta t) \cdot t}$$

Where:

LLD is the "a priori" lower limit of detection for a blank sample or background analysis as defined above (as pCi per unit mass or volume).

s_b is the square root of the background count or of a blank sample count; is the estimated standard error of a background count or a blank sample count as appropriate (in units of counts).

E is the counting efficiency (as counts per disintegration).

A is the number of gamma-rays emitted per disintegration for gamma-ray radionuclide analysis (A = 1.0 for gross alpha and tritium measurements).

V is the sample size (in units of mass or volume).

2.22 is the number of disintegrations per minute per picocurie.

Y is the fractional radio-chemical yield when applicable (otherwise Y = 1.0).

λ is the radioactive decay constant for the particular radionuclide (in units of reciprocal minutes).

Δt is the elapsed time between the midpoint of sample collection and the start time of counting. (Δt = 0.0 for environmental samples and for gross alpha measurements).

t is the duration of the count (in units of minutes).

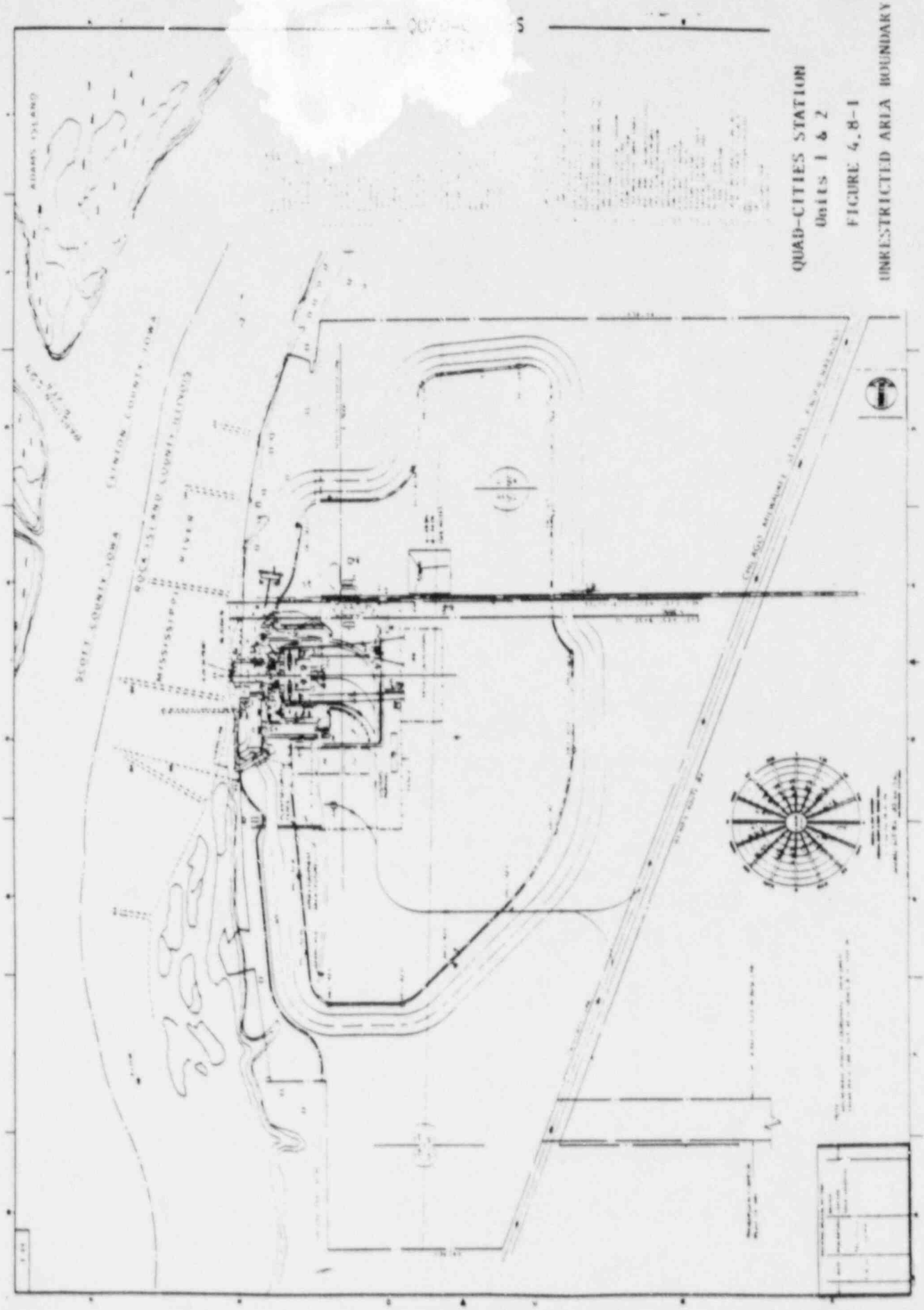
TABLE 4.8-6 (Continued)
TABLE NOTATION

The value of "s_b" used in the calculation of the LLD for a detection system shall be based on an actual observed background count or a blank sample count (as appropriate) rather than on an unverified theoretically predicted value. Typical values of "E", "V", "Y", "t", and "Δt" shall be used in the calculation.

For gamma-ray radionuclide analyses the background counts are determined from the total counts in the channels which are within plus or minus one FWHM (Full Width at Half Maximum) of the gamma-ray photopeak energy normally used for the quantitative analysis for that radionuclide. Typical values of the FWHM shall be used in the calculation.

The LLD for all measurements is defined as an "A priori" (before the fact) limit representing the capability of a measurement system and not as an "a posteriori" (after the fact) limit for a particular sample measurement.

B. Other radionuclides which are measureable and identifiable by gamma-ray spectrometry, together with the nuclides indicated in Table 4.8-6, shall also be identified and reported when an actual analysis is performed on a sample. Nuclides which are below the LLD for the analyses shall not be reported as being present at the LLD level for that nuclide.



QUAD-CITIES STATION
Units 1 & 2
FIGURE 4.8-1
UNRESTRICTED AREA BOUNDARY

3.9/4.9 AUXILIARY ELECTRICAL SYSTEMS

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to the auxiliary electrical power system.

Objective:

To assure an adequate supply of electrical power during plant operation.

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the periodic testing requirement of the auxiliary electrical system.

Objective:

To verify the operability of the auxiliary electrical system

SPECIFICATIONS

A. Normal and Emergency A-C Auxiliary Power

The reactor shall not be made critical unless all the following requirements are satisfied.

1. The Unit diesel generator and the Unit 1/2 diesel generator shall be operable.

A. Normal and Emergency A-C Auxiliary Power

1. a. Each diesel generator shall be manually started and loaded once each month to demonstrate operational readiness. The test shall continue until both the diesel engine and the generator are at equilibrium conditions of temperature while full load output is maintained.

   b. During the monthly generator test, the diesel-starting air compressor shall be checked for operation and its ability to recharge air receivers.

c. During the monthly generator test, the diesel fuel oil transfer pumps shall be operated.

2. One 345-kV line, associated switchgear, and the reserve auxiliary power transformer capable of carrying power to the unit shall be available.

2. The status of the 345-kV lines, associated switchgear, and the reserve auxiliary power transformer shall be checked daily.

3. One other 345-kV line and unit reserve aux transformer capable of carrying auxiliary power to an essential electrical bus of the unit through the 4160-volt bus tie shall be available.

3. The status of the additional source of power via the 4160-volt bus tie shall be checked daily.

4. a. The Unit engineered safety features 4160-volt buses (13-1 and 14-1, Unit 1; 23-1 and 24-1, Unit 2) are energized.

   b. The Unit engineered safety features 480-volt buses (18 and 19, Unit 1; 28 and 29, Unit 2) are energized.

4. The Unit engineered safety features 4160-volt and 480-volt buses shall be checked daily.

B. Station Batteries

The unit 24/48-volt batteries, two station 125-volt batteries, the two station 250-volt batteries, and a battery charger for each required battery shall be operable before the reactor can be made critical.

B. Station Batteries

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

2. Every 3 months the measurement shall be made of the voltage of each cell to the nearest 0.01 volt, the specific gravity of each cell, and the temperature of every fifth cell.

3. Every refueling outage, the station batteries shall be subjected to a rated load discharge test. Specific gravity and voltage of each cell shall be determined after the discharge.

C. Electric Power Availability

Whenever the reactor is in the Run mode or for startup from a hot shutdown condition, the availability of electric power shall be as specified in Specifications 3.9.A and 3.9.B except as stated in Specifications 3.9.C.1, 3.9.C.2, 3.9.C.3, and 3.9.E.

C. Electric Power Availability

The availability status of electric power shall be checked daily.

1. From and after the date that incoming power is available from only one of the lines specified in 3.9.A, continued reactor operation is permissible only during the succeeding 7 days, unless the second line is sooner made available, providing both the Unit and Unit 1/2 emergency diesel generators are operable.

2. From and after the date the incoming power is not available from any line, continued reactor operation is permissible providing both the Unit and Unit 1/2 emergency diesel generators are operating, all core and containment cooling systems are operable, reactor power level is reduced to 40% of rated, and the NRC is notified within 24 hours of the situation, the precautions to be taken during this period,and the plans for prompt restoration of incoming power.

3. From and after the date that one of the two 125/250-volt battery systems is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 3 days unless such battery system is sooner made operable.

D. Diesel Fuel

There shall be a minimum of 10,000 gallons of diesel fuel supply on site for each diesel generator.

D. Diesel Fuel

Once a month the quantity of diesel fuel available shall be logged.

Once a month a sample of diesel fuel shall be checked for quality.

E. Diesel-Generator Operability

1. Whenever the reactor is in the Startup/Hot Standby or Run mode and the unit or shared diesel generators and/or their respective associated buses are made or found to be inoperable for any reason, except as specified in Specification 3.9.E.2 below, continued reactor operation is permissible only during the succeeding 7 days provided that all of the low-pressure core cooling and all loops of the containment cooling mode of the RHR system associated with the operable diesel generator shall be operable, and two offsite lines as specified in 3.9.A are available. If this requirement cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

2. Specification 3.9.E.1 shall not apply when a diesel generator has been made inoperable for a period not to exceed 1-1/2 hours for the purpose of conducting preventative maintenance. Additionally, preventative maintenance shall not be undertaken unless two off-site lines as specified in 3.9.A are available and the alternate diesel generator has been demonstrated to be operable.

E. Diesel-Generator Operability

1. When it is determined that either the unit or shared diesel generator is inoperable, all low-pressure core cooling systems and all loops of the containment cooling modes of the RHR system associated with the operable diesel generator shall be demonstrated to be operable immediately and daily thereafter. The operable diesel generator shall be demonstrated to be operable immediately and daily thereafter.

2. During each refueling outage, a simulated loss of off-site power in conjunction with an ECCS initiation signal test shall be performed on the 4160 volt emergency bus by:

a. Verifying de-energization of the emergency buses, and load shedding from the emergency buses.

b. Verifying the diesel starts from ambient condition on the auto-start signal, energizes the emergency buses with permanently connected loads, energizes the auto-connected emergency loads through the load sequencer, and operates for greater than 5 minutes while its generator is loaded with the emergency loads.

3. When the reactor is in the Cold Shutdown or Refueling mode, a minimum of one diesel generator (either the Unit diesel generator or the Unit 1/2 diesel generator) shall be operable whenever any work is being done which has the potential for draining the vessel, secondary containment is required, or a core or containment cooling system is required.

F. REACTOR PROTECTION BUS POWER MONITORING SYSTEM

1. Two RPS electric power monitoring channels for each inservice RPS MG set or inservice alternate power source shall be OPERABLE except when the reactor is in the SHUTDOWN mode.

F. REACTOR PROTECTION BUS POWER MONITORING SYSTEM

1. The RPS Bus power monitoring system instrumentation shall be determined OPERABLE:

a. At least once per 6 months by performing a channel functional test, and

b. At least once per operating cycle by demonstrating the operability of overvoltage, undervoltage, and underfrequency protective instrumentation by performance of a channel calibration including simulated automatic activation of the protective relays, tripping logic, and output circuit breakers, and verifying the following setpoints:

(1) overvoltage	126.5 V ± 2.5%	
	Min.	123.3 V
	Max.	129.6 V
(2) undervoltage	108 V ± 2.5%	
	Min.	105.3 V
	Max.	110.7 V
(3) underfrequency	56.0 Hz ± 1% of 60 Hz	
	Min.	55.4 Hz
	Max.	56.6 Hz

2. a. With one RPS electric power monitoring channel for an inservice RPS MG set or inservice alternate power source inoperable, restore the inoperable channel to OPPERABLE status within 72 hours or remove the associated RPS MG set or alternate power source from service.

   b. With both RPS electric power monitoring channels for an inservice RPS MG set or inservice alternate power source inoperable, restore at least one channel to OPERABLE status within 30 minutes, or remove the associated RPS MG set or alternate power source from service.

3.9 LIMITING CONDITIONS FOR OPERATION BASES

A. The general objective of this specification is to assure an adequate source of electrical power to operate the auxiliaries during plant operation, to operate facilities to cool and lubricate the plant during shutdown, and to operate the engineered safety features following an accident. There are two sources of electrical energy available, namely, the 345-kV transmission system and the diesel generators.

B. The d-c supply is required for control and motive power for switchgear and engineered safety features. The electrical power required provides for the maximum availability of power, i.e., one active offsite source and one backup source of offsite power and the maximum numbers of onsite sources.

C. Auxiliary power for the Unit is supplied from two sources, either the Unit auxiliary transformer or the Unit reserve auxiliary transformer. Both of these transformers are sized to carry 100% of the auxiliary load. If the reserve auxiliary transformer is lost, the unit can continue to run for 7 days, since the Unit auxiliary transformer is available and both diesel generators are operational. A 7-day period is provided if one source of offsite power is lost. This period is based on having two diesels operable which are adequate to handle an accident assuming a single failure. In addition, auxiliary power from the other unit can be obtained through the 4160-volt bus tie. If both offsite lines are lost, power is reduced to 40% of rated so that the turbine bypass system could accept the steam flow without reactor trip should the generator be separated from the system or a turbine trip occur. In this condition, the turbine-generator is capable of supplying house load and ECCS load if necessary through the unit auxiliary transformer. If the unit were shut down on loss of both lines, fewer sources of power would be available than for sustained operation at 40% power. Attention will be given to restoring normal offsite power to minimize the length of time operation is allowed in a condition where both sources are available.

In the normal mode of operation, the 345-kV system is operable and two diesel generators are operable. One diesel generator may be allowed out of service for a short period of time to conduct preventative maintenance provided that power is available from the 345-kV system through a 4160-volt bus tie to supply the emergency buses, and the alternate diesel generator is proven operable. Offsite power is quite reliable, and in the last 25 years there has been only one instance in which all offsite power was lost at a Commonwealth Edison Generating Station. When the unit or shared diesel generator is made or found inoperable for reasons other than preventative maintenance, the remaining diesel generator and its associated low-pressure core cooling

and containment cooling systems, which provide sufficient engineered safety features equipment to cover all breaks, will be proven operable.

D. The diesel fuel supply of 10,000 gallons will supply each diesel generator with a minimum of 2 days of full load operation or about 4 days at 1/2 load. Additional diesel fuel can be obtained and delivered to the site within an 8-hour period; thus a 2-day supply provides for adequate margin.

E. Diesel generator operability is discussed in Paragraph 3.9.C above.

F. Specifications are provided to ensure the operability of the RPS Bus electrical protection assemblies (EPA's). Each RPS MG set and the alternate power source has 2 EPA channels wired in series. A trip of either channel from either overvoltage, undervoltage, or underfrequency will trip the associated MG set or alternate power source.

4.9 SURVEILLANCE REQUIREMENTS BASES

A. The monthly test of the diesel generator is conducted to check for equipment failures and deterioration. Testing is conducted up to equilibrium operating conditions to demonstrate proper operation at these conditions. The diesel will be manually started, synchronized to the bus, and load picked up. The diesel shall be loaded to at least half load to prevent fouling of the engine. It is expected that the diesel generator will be run for 1 to 2 hours. Diesel-generator experience at other Commonwealth Edison generating stations indicates that the testing frequency is adequate and provides a high reliability of operation should the system be required. In addition, during the test, the generator is synchronized to the offsite power sources and thus not completely independent of this source. To maintain the maximum amount of independence, a 30-day testing interval is also desirable.

Each diesel generator has two air compressors and four air tanks. Two air tanks are piped together to form an air receiver. Each air compressor supplies an air receiver. This arrangement provides redundency in starting capability. It is expected that the air compressors will run only infrequently.

During the monthly check of the diesel, the receivers will be drawn down below the point at which the compressor automatically starts to check operation and the ability of the compressors to recharge the receivers. Pressure indicators are provided on each of the receivers.

Following the monthly test of the diesels, the fuel oil day tank will be approximately half full based on the 2-hour test at full load and 205 gph at full load. At the end of the monthly load test of the diesel generators, the fuel oil transfer pumps will be operated to refill the day tank and to check the operation of these pumps from the emergency source.

The test of the emergency diesel generator during the refueling outage will be more comprehensive in that it will functionally test the system, i.e., it will check diesel starting, closure of diesel breaker, and sequencing of loads on the diesel. The diesel will be started by simulation of a loss-of-coolant accident. In addition, an undervoltage condition will be imposed to simulate a loss of the time required. The only load on the diesel is that due to friction and windage and a small amount of bypass flow on each pump.

Periodic tests between refueling outages verify the ability of the diesel to run at full load and the core and containment cooling pumps to deliver full flow. Periodic testing of the various components plus a functional test at the refueling interval are sufficient to maintain adequate reliability.

B. Although station batteries will deteriorate with time, utility experience indicates there is almost no possibility of precipitous failure. The type of surveillance described in this specification is that which has been demonstrated over the years to provide an indication of a cell becoming irregular or unserviceable long before it becomes a failure.

In addition, the checks described also provide adequate indication that the batteries have the specified ampere-hour capability.

C. Because the availability of electricity to the system is a normal operating function, a check of the status of these systems provides adequate surveillance.

D. The diesel fuel oil quality must be checked to ensure proper operation of the diesel generators. Water content should be minimized, because water in the fuel would contribute to excessive corrosion of the system, causing decreased reliability. The growth of micro-organisms results in slime formations, which are one of the chief causes of jellying in hydrocarbon fuels. Minimizing of such slimes is also essential to assuring high reliability.

E. Diesel-generator operability surveillance is discussed in Paragraph 4.9.A above.

F. Surveillance requirements are provided for the RPS EPA's to demonstrate their operability. The setpoints for overvoltage, undervoltage, and underfrequency have been chosen based on analysis (ref. February 4, 1983 letter to H. Denton from T. Rausch).

3.10/4.10 REFUELING

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to fuel handling and core reactivity limitations.

Objective:

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

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the periodic testing of those interlocks and instruments used during refueling.

Objective:

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

SPECIFICATIONS

A. Refueling Interlocks

The reactor mode switch shall be locked in the Refuel position during core alterations, and the refueling interlocks listed below shall be operable except as specified in Specifications 3.10.D and 3.10.E.

1. Control Rod Blocks

   a. Mode switch in Startup/Hot Standby and refueling platform over the reactor.

   b. Fuel on any refueling hoist and refueling platform over the reactor.

   c. Mode switch in Refuel with one control rod withdrawal permit.

2. Refueling Platform Reverse Motion (toward reactor vessel) Block

A. Refueling Interlocks

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

a. Mode switch in Startup/ Hot Standby.

b. Any control rod out and fuel on any refueling hoist.

3. Refueling Platform Hoist Blocks

a. Any control rod out and fuel on any refueling hoist over the vessel.

b. Hoist overload.

c. High position limitation.

B. Core Monitoring

During core alterations, two SRM's shall be operable, one in the core quadrant where fuel or control rods are being moved and one in an adjacent quadrant. For an SRM to be considered operable, the following conditions shall be satisfied:

1. The SRM shall be inserted to the normal operating level (use of special movable, dunking type detectors during initial fuel loading and major core alterations in place of normal detectors is permissible as long as the detector is connected into the proper circuitry which contains the required rod blocks).

B. Core Monitoring

Prior to any alterations to the core, the SRM's shall be functionally tested and checked for neutron response. Thereafter, the SRM's shall be checked daily for response, except when the conditions of 3.10.B.2.a and 3.10.B.2.b are met.

2. The SRM or dunking type detector shall have a minimum of 3 cps with all rods fully inserted in the core except when both of the following conditions are fulfilled:

   a. No more than two fuel assemblies are present in the core quadrant associated with the SRM.

   b. While in core, these fuel assemblies are in locations adjacent to the SRM.

C. Fuel Storage Pool Water Level

Whenever irradiated fuel is stored in the fuel storage pool, the pool water level shall be maintained at a level of at least 33 feet.

C. Fuel Storage Pool Water Level

Whenever irradiated fuel is stored in the fuel storage pool, the pool level shall be recorded daily.

D. Control Rod and Control Drive Maintenance

A maximum of two nonadjacent control rods separated by more than two control cells in any direction may be withdrawn from the core for the purpose of performing control rod and/or control rod drive maintenance provided the following conditions are satisfied:

1. The reactor mode switch shall be locked in the Refuel position. The refueling interlock which prevents more than one control rod from being withdrawn may be bypassed for one of the control rods on which maintenance is being performed. All other refueling interlocks shall be operable.

D. Control Rod and Control Rod Drive Maintenance.

1. Sufficient control rods shall be withdrawn prior to performing this maintenance to demonstrate with a margin of 0.25% Δk that the core can be made subcritical at any time during the maintenance with the strongest operable control rod fully withdrawn and all other operable rods fully inserted.

Alternately, if a minimum of eight control rods surrounding each control rod out of service for maintenance are to be fully inserted and have their directional control valves electrically disarmed, the 0.25% Δk margin will be met with the strongest control rod remaining in service during the maintenance period fully withdrawn.

2. Specification 3.3.A.1 shall be met, or the control rod directional control valves for a minimum of eight control rods surrounding each drive out of service for maintenance will be disarmed electrically and sufficient margin to criticality demonstrated.

3. SRM's shall be operable (a) in each core quadrant containing a control rod on which maintenance is being performed, and (b) in a quadrant adjacent to one of the quadrants specified in Specification 3.10.D.3.(a) above. Requirements for an SRM to be considered operable are given in Specification 3.10.B.

E. Extended Core Maintenance

More than two control rods may be withdrawn from the reactor core provided the following conditions are satisfied:

E. Extended Core Maintenance

Prior to control rod withdrawal for extended core maintenance, that control rod's control cell shall be certified to contain no fuel assemblies.

1. The reactor mode switch shall be locked in the Refuel position. The refueling interlock which prevents more than one control rod from being withdrawn may be bypassed on a withdrawn control rod after the fuel assemblies in the cell containing (controlled by) that control rod have been removed from the reactor core. All other refueling interlocks shall be operable.

2. SRM's shall be operable in the core quadrant where fuel or control rods are being moved and in an adjacent quadrant. The requirements for an SRM to be considered operable are given in Specification 3.10.B.

F. Spent Fuel Cask Handling

1. Fuel Cask handling above the 623' level of the Reactor Building will be done with the reactor building crane in the RESTRICTED MODE only, except as specified in 3.10.F.2.

F. Spent Fuel Cask Handling

1. Prior to fuel cask handling operations, the redundant crane including the rope, hooks, slings, shackles and other operating mechanisms will be inspected.

   The rope will be replaced if any of the following conditions exist:

   a. Twelve (12) randomly distributed broken wires in one lay or four (4) broken wires in one strand of one rope lay.

   b. Wear of one-third the original diameter of outside individual wire.

c. Kinking, crushing, or any other damage resulting in distortion of the rope.

d. Evidence of any type of heat damage.

e. Reductions from nominal diameter of more than 1/16 inch for a rope diameter from 7/8" to 1 1/4" inclusive.

2. Fuel cask handling in other than the RESTRICTED MODE will be permitted in emergency or equipment failure situations only to the extent necessary to get the cask to the closest acceptable stable location.

2. Prior to operations in the RESTRICTED MODE

a. The controlled area limit switches will be tested;

b. the "two-block" limit switches will be tested;

c. the "inching hoist" controls will be tested.

3. Operation with a failed controlled area limit switch is permissible for 48 hours providing an operator is on the refueling floor to assure the crane is operated within the restricted zone painted on the floor.

3. The empty spent fuel cask will be lifted free of all support by a maximum of 1 foot and left hanging for 5 minutes prior to any series of fuel cask handling operations.

3.10 LIMITING CONDITIONS FOR OPERATION BASES

A. 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.

To minimize the possibility of loading fuel into a cell containing no control rod, it is required that all control rods are fully inserted when fuel is being loaded into the reactor core. This requirement assures that during refueling, the refueling interlocks will prevent inadvertent criticality as designed. The core reactivity limitation of Specification 3.2 limits the core alterations to assure that the resulting core loading can be controlled with the reactivity control system and interlocks at any time during shutdown or the following operating cycle.

The addition of large amounts of reactivity to the core is prevented by operating procedures, which are in turn backed up by refueling interlocks 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.

B. The SRM are provided to monitor the core during periods of station shutdown and to guide the operator during refueling operations and station startup. Requiring two operable SRM in or adjacent to any core quadrant where fuel or control rods are being moved assures adequate monitoring of that quadrant during such alterations. Requiring a minimum of 3 counts per second whenever criticality is possible provides assurance that neutron flux is being monitored. Criticality is considered to be impossible if there are no more than two assemblies in a quadrant and if these are in locations adjacent to the SRM. In this case only, the SRM or dunking type detector count rate is permitted to be less than 3 counts per second.

C. To assure that there is adequate water to shield and cool the irradiated fuel assemblies stored in the pool, a minimum pool water level is established. The minimum water level of 33 feet is established because it would be a significant change from the normal level (37 feet 9 inches), well above a level to assure adequate cooling (just above active fuel), and above the level at which GSEP action is initiated (5 feet uncontrolled loss of level with level decreasing).

D. During certain periods, it is desirable to perform maintenance on two control rods and/or control rod drives at the same time. This specification provides assurance that inadvertent criticality does not occur during such maintenance.

The maintenance is performed with the mode switch in the Refuel position to provide the refueling interlocks normally available during refueling operations as explained in Part A of these Bases. In order to withdraw a second control rod after withdrawal of the first rod, it is necessary to bypass the refueling interlock on the first control rod which prevents more than one control rod from being withdrawn at the same time. The requirement that an adequate shutdown margin be demonstrated with the control rods remaining in service ensures that inadvertent criticality cannot occur during this maintenance. The shutdown margin is verified by demonstrating that the core is shut down even if the strongest control rod remaining in service is fully withdrawn. Disarming the directional control valves does not inhibit control rod scram capability.

E. The intent of this specification is to permit the unloading of a significant portion of the reactor core for such purposes as inservice inspection requirements, examination of the core support plate, etc. This specification provides assurance that inadvertent criticality does not occur during such operation.

This operation is performed with the mode switch in the Refuel position to provide the refueling interlocks normally available during refueling as explained in the bases for Specification 3.10.A. In order to withdraw more than one control rod, it is necessary to bypass the refueling interlock on each withdrawn control rod which prevents more than one control rod from being withdrawn at a time. The requirement that the fuel assemblies in the cell controlled by the control rod be removed from the reactor core before the interlock can be bypassed ensures that withdrawal of another control rod does not result in inadvertent criticality. Each control rod essentially provides reactivity control for the fuel assemblies in the cell associated with that control rod. Thus, removal of an entire cell (fuel assemblies plus control rod) results in a lower reactivity potential of the core.

The operation of the redundant crane in the Restricted Mode during fuel cask handling operations assures that the cask remains within the controlled area once it has been removed from its transport vehicle (i.e., once it is above the 623 foot elevation). Handling of the cask on the Refueling Floor in the Unrestricted Mode is allowed only in the case of equipment failures or emergency conditions when the cask is already suspended. The Unrestricted Mode of operation is allowed only

to the extent necessary to get the cask to a suitable stationary position so the required repairs can be made. Operation with a failed controlled area microswitch will be allowed for a 48-hour period providing an Operator is on the floor in addition to the crane operator to assure that the cask handling is limited to the controlled area as marked on the floor. This will allow adequate time to make repairs but still will not restrict cask handling operations unduly.

The Surveillance Requirements specified assure that the redundant crane is adequately inspected in accordance with the accepted ANSI Standard (B.30.2.0) and manufacturer's recommendations to determine that the equipment is in satisfactory condition. The testing of the controlled area limit switches assures that the crane operation will be limited to the designated area in the Restricted Mode of operation. The test of the "two-block" limit switch assures the power to the hoisting motor will be interrupted before an actual "two-blocking" incident can occur. The test of the inching hoist assures that this mode of load control is available when required.

Requiring the lifting and holding of the cask for 5 minutes during the initial lift of each series of cask handling operations puts a load test on the entire crane lifting mechanism as well as the braking system. Performing this test when the cask is being lifted initially from the cask car assures that the system is operable prior to lifting the load to an excessive height.

4.10 SURVEILLANCE REQUIREMENTS BASES

Refer to Specifications 4.10.A through 4.10.E.

3.11/4.11 HIGH ENERGY PIPING INTEGRITY (OUTSIDE CONTAINMENT)

LIMITING CONDITIONS FOR OPERATION

Applicability:

Applies to operating status of certain piping outside primary containment.

Objective:

To assure the integrity of sections of piping which is postulated to effect safe plant shutdown.

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the periodic examination requirements for certain piping outside primary containment.

Objective:

To determine the condition of the sections of piping.

SPECIFICATIONS

The high energy piping sections identified in Table 4.11-1 shall be maintained free of visually observable through wall leaks.

1. If a leak is detected by the surveillance program of Specification 4.11, efforts to identify the source of the leaks shall be started immediately.

2. If the source of leakage cannot be identified within 24 hours of detection or if the leak is found to be from a break in the piping sections identified in Table 4.11-1, the pressure within the section of piping shall be brought to atmospheric pressure within 48 hours.

3. When the modifications identified in Commonwealth Edison's letter to the NRC dated September 16, 1975 (G. Abrell to D. Ziemann) have been completed, Technical Specifications 3.11 and 4.11 will no longer be required.

The inspections listed in Table 4.11-1 shall be performed as specified.

3.11/4.11 BASES

Intensive analysis and review has shown that there are specific postulated high energy piping system failures which have the potential to inhibit safe cold shutdown of the reactor. This conclusion is based on utilizing the basic NRC high energy line break criteria. To reduce the probability of such failures, certain plant modifications are necessary. Until these modifications are complete, additional surveillance will be performed during plant operation to enhance the detection of piping system defects. The inservice examination and the frequency of inspection will provide a means for timely detection of such piping defects.

TABLE 4.11-1

SURVEILLANCE REQUIREMENTS FOR HIGH ENERGY PIPING OUTSIDE CONTAINMENT

Piping	Surveillance Area	Surveillance Technique	Frequency
Main Steam	From primary containment penetration to secondary containment penetration	Visual(1)	30 days
Reactor Feedwater Piping	From primary containment penetration to secondary containment penetration and "A"(2) reactor feed pump discharge to the 24-inch diameter feedwater header	Visual(1)	30 days
HPCI Steam Piping	From the primary containment penetration to the reactor building penetration	Visual(1)	30 days
RCIC Steam Piping	From primary containment penetration to the RCIC turbine.	Visual(1)	30 days

Notes:

(1) Visual observation of piping insulation and area for evidence of wetness or any physical damage resulting from a leak. Surveillance to be performed using normal access without scaffolding or any other access aids.

(2) "A" Reactor feed pump for Unit 1 "C" Reactor feed pump for Unit 2.

3.12/4.12 FIRE PROTECTION SYSTEMS

LIMITING CONDITIONS FOR OPERATIONS

Applicability:

Applies to the fire protection systems whenever the equipment or systems being protected are required to be operable.

Objective:

To ensure that adequate protection against fires is maintained during all modes of facility operation.

SURVEILLANCE REQUIREMENTS

Applicability:

Applies to the periodic testing requirements of the fire protection systems whenever the fire protection systems are required to be operable.

Objective:

To verify operability of the fire protection systems.

SPECIFICATIONS

A. Fire Detection Instumentation

1. As a minimum, the fire detection instrumentation for each fire detection zone shown in Table 3.12-1 shall be operable at all times when equipment in that fire detection zone is required to be operable.

2. With the number of operable fire detection instruments less than required by Table 3.12-1:

   a. Perform an inspection of affected zone, within 1 hour. Perform additional inspections at least once per hour except in inaccessible areas.

   b. Restore the inoperable instrument(s) to operable status within 14 days or prepare and submit a report to the Commission pursuant

A. Fire Detection Instrumentation

1. Each of the fire detection instruments given by Table 3.12-1 shall be demonstrated operable at least once per 6 months by a channel functional test.

2. All non-supervised circuits shall be demonstrated operable once per month.

to Specification 6.3.A.1 within the next 30 days outlining the cause of the malfunction, the action taken, and the plans for restoring the instrument(s) to operable status.

3. The provisions of Specification 3.0.A are not applicable.

B. Fire Suppression Water System

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

a. Two (2) 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 Mississippi River and transferring the water through distribution piping with operable sectionalizing control or isolation valves to the yard hydrant curb valves and the front valve ahead of the water flow alarm device on each sprinkler, hose stand pipe, or spray system riser.

B. Fire Suppression Water System

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

a. At least once per 31 days on a staggered test basis by starting each pump and operating it for at least 20 minutes on recirculation flow.

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path is in the correct position.

c. At least once per year by performance of a system flush.

d. At least once per year by cycling each testable valve in the flow path through at least one complete cycle of full travel.

e. At least once per operating cycle

1) By performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence and verifying that each automatic valve in the flow path actuates to its correct position.

2) By verifying that each pump develops at least 2000 gpm at a system head of 123 psig.

3) Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel, and

f. At least once per 3 years by performing flow tests of the system in accordance with Chapter 5, Section II, NFPA Fire Protection Handbook.

2. With inoperable fire pumps or associated water supply, restore the inoperable equipment to operable status within 7 days, or prepare and submit a report to the Commission pursuant to Specification 6.3.A.1 within the next 30 days outlining the plans and procedures to be used to provide for the loss of redundancy in this system.

3. With no Fire Suppression Water System operable, within 24 hours:

   a. Establish a backup Fire Suppression Water System.

   b. Notify the Commission pursuant to Specification 6.3.A.1 outlining the actions taken, the cause of the inoperability, and the plans and schedule for restoring the system to operable status.

4. If the requirements of Specification 3.12.B.3.a cannot be met, an orderly shut down shall be initiated, and the reactor shall be in a cold shut down condition within 24 hours.

C. Sprinkler Systems

1. The sprinkler systems given in Table 3.12-2 shall be operable at all times when equipment in the areas spray/sprinkler protected is required to be operable.

C. Sprinkler Systems

1. At least once per year by cycling each testable valve in the flow path through at least one complete cycle of full travel.

2. With a sprinkler system inoperable, establish backup fire suppression equipment and inspect the area twice per shift.

2. At least once per operating cycle:

   a. A system functional test shall be performed which includes simulated automatic actuation of the system and verifying that the automatic valves in the flow path actuate to their correct positions.

   b. The sprinkler headers shall be inspected to verify their integrity.

   c. Each nozzle shall be inspected to verify no blockage.

3. Restore the system to operable status within 14 days, or prepare and submit a report to the Commission pursuant to Specification 6.3.A.1 within the next 30 days outlining the cause of inoperability, the action taken, and the plans for restoring the system to operable status.

3. At least once per 3 years by performing an air flow test through each open head spray/sprinkler header and verifying each open head spray/sprinkler nozzle is unobstructed.

4. The provisions of Specification 3.0.A are not applicable.

D. CO_2 Systems

1. The CO_2 Storage Tank shall have a minimum standby level of 50 percent and a minimum pressure of 250 psig.

D. CO_2 Systems

1. At least once per 7 days the CO_2 Storage Tank level and pressure will be verified.

2. The CO_2 Systems given in Table 3.12-3 shall be operable.

2. At least once per operating cycle, the system valves and associated dampers will be verified to actuate automatically and manually. A brief flow test shall be made to verify flow from each nozzle.

3. Specifications 3.12.D.1 and 3.12.D.2 above apply when the equipment in the areas given in Table 3.12-3 is required to be operable.

4. With a CO_2 System inoperable, establish backup fire suppression equipment for the unprotected area(s) within 1 hour and inspect the area twice per shift.

5. Restore the system to operable status within 14 days, or prepare and submit a report to the Commission pursuant to Specification 6.3.A.1 within the next 30 days outlining the cause of inoperability, the action taken, and the plans and schedule for restoring the system to operable status.

6. If actuated, the storage tank will be restored to greater than the minimum level within 48 hours.

7. The provisions of Specification 3.0.A are not applicable.

E. Fire Hose Stations

1. The Fire Hose Stations given in Table 3.12-4 shall be operable at all times when the equipment in the areas protected by the fire hose is required to be operable.

2. With a hose station inoperable, route an additional equivalent capacity hose to the unprotected area from an operable hose station within 1 hour.

3. The provisions of Specification 3.0.A are not applicable.

E. Fire Hose Stations

1. At least once per 31 days, a visual inspection of each fire hose station shall be made to assure all equipment is available at the station.

2. At least once per operating cycle, the hose will be removed for inspection and reracked. Degraded gaskets in the couplings will be replaced.

3. At least once per 3 years, each hose station valve will be partially opened to verify valve operability and no blockage.

4. At least once per 3 years a hydrostatic test will be conducted on each hose at a pressure at least 50 psig greater than the maximum pressure available at the hose station.

F. Penetration Fire Barriers

1. All penetration fire barriers protecting safety related areas shall be intact except as stated in Specification 3.12.F.2.

F. Penetration Fire Barriers

1. Each of the penetration fire barriers shall be verified to be intact by visual inspection:

   a. At least once per operating cycle, and

   b. Prior to declaring a penetration fire barrier functional following repairs or maintenance.

2. With one or more penetration fire barriers not intact, establish a continuous fire watch on at least one side of the affected penetration within 1 hour if the area on either side of the affected penetration contains equipment required to be operable.

3. The provisions of Specification 3.0.A are not applicable.

G. Fire Pump Diesel Engine

1. The Fire Pump Diesel Engine shall be operable as specified in 3.12.B.1.a and 3.12.B.1.b.

G. Fire Pump Diesel Engine

1. The fire pump diesel starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

   a. At least once per 7 days by verifying that:

      1) The electrolyte level of each battery is above the plates, and
      (2) The overall battery voltage is $\geq$ 24 volts.

   b. At least once per 92 days by verifying that the specific gravity is appropriate for continued service of battery.

   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 anti-corrosion material.

2. The fire pump diesel engine shall be demonstrated OPERABLE:

   a. At least once per 31 days by verifying:

      1) The fuel storage day tank contains at least 150 gallons of fuel, and

      2) The diesel starts from ambient conditions and operates for at least 20 minutes.

   b. At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank shall be checked for quality using existing station procedures for diesel oil in the main storage tanks.

   c. At least once per 18 months, during shutdown, by:

      1) Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service, and

      2) Verifying the diesel starts from ambient conditions on the autostart signal and operates for $\geq$ 20 minutes while loaded with the fire pump.

3.12/4.12 LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS BASES

The operability of the fire suppression systems insures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety-related equipment is located. The fire suppression system consists of the water system, sprinklers, CO_2, and fire hose stations. The collective capability of the fire suppression systems is adequate to minimize potential damage to safety-related equipment, and is a major element in the facility fire protection program.

Operability of the fire detection instrumentation ensures that auequate warning capability is available for the prompt detection of fires. This capability is required in order to detect and locate fires in their early stages. Prompt detection of fires will reduce the potential for damage to safety-related equipment, and is an integral element in the overall facility fire protection program. In the event that a portion of the fire detection instrumentation is inoperable, the establishment of frequent fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is returned to service.

In the event that portions of the fire suppression systems are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the affected equipment can be restored to service.

A fire suppression water system shall consist of a water source, pumps, and distribution piping with associated valves. Such valves shall include yard hydrant curb valves, and the first valve ahead of the water flow alarm device on each sprinkler or hose standpipe riser.

In the event that the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant. The requirements for a 24-hour report to the Commission provides for prompt evaluation of the acceptability of the corrective measures to provide adequate fire suppression capability for the continued protection of the nuclear plant.

The functional integrity of the penetration fire barriers ensures that fires will be confined or adequately retarded from spreading to adjacent portions of the facility. This design feature minimizes the possibility of a single fire rapidly involving several areas of the facility prior to detection and extinguishment. The penetration fire barriers are a passive element in the facility fire protection program and are subject to periodic inspections.

TABLE 3.12-1

FIRE DETECTION INSTRUMENTS

INSTRUMENT LOCATION	MINIMUM INSTRUMENTS OPERABLE		
	Heat	Smoke	Flow
Unit 1 HPCI area: 7 heat detectors	5		
Unit 1 Diesel Generator Room: 2 heat detectors	1		
Unit 1 Diesel Oil Day Tank Area: 1 heat detector	1		
Unit 1/2 Diesel Generator Room 2 heat detectors	1		
Unit 1/2 Diesel Oil Day Tank Area: 1 heat detector	1		
Unit 1 Cable Tunnel. 1 flow detector			1
Control Room, Computer Room Electrical Equipment Room HVAC: 10 smoke detectors		8	
Cable Spreading Room Area: 18 smoke detectors		12	

TABLE 3.12-2

SPRINKLER SYSTEMS

1. Unit One Cable Tunnel
2. Unit One HPCI Room
3. Unit One Diesel Oil Day Tank Room
4. Unit 1/2 Diesel Oil Day Tank Room
5. Cable Spreading Room

TABLE 3.12-3

CO_2 SYSTEMS

1. Unit One Diesel Generator Area
2. Unit 1/2 Diesel Generator Area
3. Unit One Diesel Oil Day Tank Room
4. Unit 1/2 Diesel Oil Day Tank Room

TABLE 3.12-4

FIRE HOSE STATIONS

NO.	SIZE	LOCATION
F168	100 ft.	Outside South Entrance to Control Room
F169	100 ft.	Outside Cable Spreading Room
F170	100 ft.	Outside Cable Spreading Room
F111	100 ft.	Outside Battery Charger Room near MCC 15-1
F171	100 ft.	Outside Electrical Equipment Room
F172	100 ft.	Outside Electrical Equipment Room near Machine Shop
F129	100 ft.	Above Cable Tunnel at Column 17-G
F130	100 ft.	Outside DG1 at column 23-G
F156	100 ft.	Outside DG 1/2 at column 14-N
F138	100 ft.	Outside RHR Service Water Pump rooms by column 18-D
F158	100 ft.	South RHR Room
F159	100 ft.	North RHR Room
F160	100 ft.	Outside North Core Spray Room
F161	100 ft.	Outside South Core Spray Room
CO-3B	150 ft.	Outside Battery Charger Room near MCC 18-2
F142	100 ft.	Standby Liquid Control Area
F143	100 ft.	Standby Liquid Control Area
F106	100 ft.	Between Bus 13-1 and Bus 14-1
CO-2A	150 ft.	South of Bus 14-1
CO-4B	150 ft.	Northwest of DG1 Room
F155	100 ft.	MCC 18/19-5
F151	100 ft.	Southwest of MCC 18-1A

5.0 DESIGN FEATURES

5.1 SITE

The Quad-Cities Station, which consists of a tract of land of approximately 404 acres, is located about 3 miles north of Cordova, Illinois, Rock Island County, Illinois. The tract is situated in portions of Sections 7, 8, 17, and 18 of Township 20 North, Range 2 East.

5.2 REACTOR

A. The core shall consist of not more than 724 fuel assemblies.

B. The reactor core shall contain 177 cruciform-shaped control rods. The control material shall be boron carbide power (B_4C) compacted to approximately 70% of theoretical density or hafnium metal.

5.3 REACTOR VESSEL

The reactor vessel shall be as described in Table 4.1.1 of the SAR. The applicable design codes shall be as described in Table 4.1.1 of the SAR.

5.4 CONTAINMENT

A. The principal design parameters and applicable design codes for the primary containment shall be as given in Table 5.2.1 of the SAR.

B. The secondary containment shall be as described in Section 5.3.2 of the SAR, and the applicable codes shall be as described in Section 12.1.1.3 of the SAR.

C. Penetrations to the primary containment and piping passing through such penetrations shall be designed in accordance with standards set forth in Section 5.2.2 of the SAR.

5.5 FUEL STORAGE

A. The new fuel storage facility shall be such that the K_{eff} dry is less than 0.90 and flooded is less than 0.95.

B. The K_{eff} of the spent fuel storage pool shall be less than or equal to 0.95.

5.6 SEISMIC DESIGN

The reactor building and all contained engineered safeguards are designed for the maximum credible earthquake ground motion with an acceleration of 24% of gravity. Dynamic analysis was used to determine the earthquake acceleration application to the various elevations in the reactor building.

6.0 ADMINISTRATIVE CONTROLS

6.1 ORGANIZATION, REVIEW, INVESTIGATION, AND AUDIT

A. The Station Manager shall have overall full-time responsibility for safe operation of the facility. During periods when the Station Manager is unavailable, he shall designate this responsibility to an established alternate who satisfies the ANSI N18.1 of March 8, 1971 experience requirements for plant manager.

B. The organization chart of the corporate management which relates to the operation of this station and the normal functional organization chart for operation of the station are shown in Figures 6.1-1 and 6.1-2 respectively.

C. The shift manning for the station shall be as shown in Figure 6.1-3. The Assistant Superintendent Operating, Operating Engineer, Shift Engineers, and Shift Foremen shall have a senior operator's license. The Fuel Handling Foreman has a limited Senior Operator's License. The Assistant Vice President and General Manager Nuclear Stations on the corporate level has responsibility for the Fire Protection Program. The Assistant Superintendent Maintenance will be responsible for implementation of the Fire Protection Program. A fire brigade of at least 5 members shall be maintained on-site at all times. This excludes the shift crew necessary for safe shutdown of the plant, and any personnel required for other essential functions during a fire emergency.

D. Qualifications of the station management and operating staff, excluding the Rad-Chem Supervisor and the Radiation/Chemical Technicians, shall meet minimum acceptable levels as described in ANSI N18.1, "Selection and Training of Nuclear Power Plant Personnel", dated March 8, 1971. The Rad-Chem Supervisor or the Lead Health Physicist shall meet the requirements of radiation protection manager of Regulatory Guide 1.8. The individual filling the position of Assistant Superintendent - Technical Services shall meet the minimum acceptable level for "Technical Manager" as described in Section 4.2.4 of ANSI N18.1-1971. The Shift Technical Advisor shall have a 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.

The Radiation/Chemical Technicians shall have successfully completed the established Radiation/Chemical Technician training program, and shall have at least a total of one year of general power plant, chemical, or radiation protection experience, or equivalent training. The Radiation/Chemical Technicians shall meet the criteria for "Individuals Qualified in Radiation Protection Procedures", as described in the D.L. Ziemann (NRC) letter to R. L. Bolger (CECo.) dated March 15, 1977. The Radiation/Chemical Technician training program consists of the following:

1. Satisfactory completion of a 12-week academic program. Topics of this course include mathematics, nuclear physics, radioactive decay, chemistry, sampling techniques, reactor coolant parameters, radiation exposure, shielding, biological effects of radiation exposure, radiation survey techniques, personnel monitoring, and emergency procedures.

2. Satisfactory performance on a comprehensive examination following completion of academic training.

3. On-Shift training under the supervision of a qualified Radiation/Chemical Technician.

E. Retraining and replacement training of Station personnel shall be in accordance with ANSI N18.1, "Selection and Training of Nuclear Power Plant Personnel", dated March 8, 1971.

A training program for the fire brigade shall be maintained under the direction of the Station Fire Marshal and shall meet or exceed the requirements of Section 27 of the NFPA Code-1975 except that training sessions shall be at least quarterly.

F. Retraining for licensed operators, senior operators, and senior operators (limited) shall be conducted at intervals not exceeding 2 years.

G. The Review and Investigative Function and the Audit Function of activities affecting quality during facility operations shall be constituted and have the responsibilities and authorities outlined below:

1. The Supervisor of the Offsite Review and Investigative Function shall be appointed by the Chairman and President. The Audit Function shall be the responsibility of the Manager of Quality Assurance and shall be independent of operations.

a. Offsite Review and Investigative Function

The Supervisor of the Offsite Review and Investigative Function shall: (1) provide directions for the review and investigative function and appoint a senior participant to provide appropriate direction, (2) select each participant for this function, (3) select a complement of more than one participant who collectively possess background and qualifications in the subject matter under review to provide comprehensive interdisciplinary review coverage under this function, (4) independently review and approve the findings and recommendations developed by personnel performing the review and investigative function, (5) approve and report in a timely manner all findings of noncompliance with NRC requirements to the Station Manager, Assistant Vice President and General Manager Nuclear Stations, Manager of Quality Assurance, and the Vice President of Nuclear Operations. During periods when the Supervisor of Offsite Review and Investigative Function is unavailable, he shall designate this responsibility to an established alternate, who satisfies the formal training and experience requirements for the Supervisor of the Offsite Review and Investigative Function. The responsibilities of the personnel performing this function are stated below. The Offsite Review and Investigative Function shall review:

1) The safety evaluations for (1) changes to procedures, equipment, or systems as described in the safety analysis report and (2) tests or experiments completed under the provision of 10 CFR 50.59 to verify that such actions did not constitute an unreviewed safety question. Proposed changes to the Quality Assurance Program description shall be reviewed and approved by the Manager of Quality Assurance.

2) Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in 10 CFR 50.59.

3) Proposed tests or experiments which involve an unreviewed safety question defined in 10 CFR 50.59.

4) Proposed changes in Technical Specification NRC operating licenses.

5) Noncompliance with NRC requirements, or of internal procedures, or instructions causing nuclear safety significance.

6) Significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety as referred to it by the Onsite Review and Investigative Function.

7) Reportable events.

8) All recognized indications of an unanticipated deficiency in some aspect of design or operation of safety-related structures, systems, or components.

9) Review and report findings and recommendations regarding all changes to the Generating Stations Emergency Plan prior to implementation of such change.

10) Review and report findings and recommendations regarding all items referred by the Technical Staff Supervisor, Station Manager, Assistant Vice President and General Manager Nuclear Stations, and Manager of Quality Assurance.

b. Audit Function

The Audit Function shall be the responsibility of the Manager of Quality Assurance independent of the Production Department. Such responsibility is delegated to the Director of Quality Assurance for Operating and to the General Supervisor Quality Assurance Maintenance for maintenance quality assurance activities.

Either shall approve the audit agenda and checklists, the findings and the report of each audit. Audits shall be performed in accordance with the Company Quality Assurance Program and Procedures. Audits shall be performed to assure that safety-related functions are covered within a period of 2 years or less as designated below.

1) Audit of the conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions at least once per year.

2) Audit of the adherence to procedures, training and qualification of the station staff at least once per year.

3) Audit of the results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or methods of operation that affect nuclear safety at least once per 6 months.

4) Audit of the performance of activities required by the Quality Assurance Program to meet the Criteria of Appendix "B" 10 CFR 50.

5) Audit of the Facility Emergency Plan and implementing procedures at least once per year.

6) Audit of the Facility Security Plan and implementing procedures at least once per year.

7) Audit onsite and offsite reviews.

8) Audit the Facility Fire Protection Program and implementing procedures at least once per 24 months.

9) The radiological environmental monitoring program and the results thereof at least once per 12 months.

10) The ODCM and implementing procedures at least once per 24 months.

11) The PCP and implementing procedures for solidification of radioactive waste at least once per 24 months.

12) Report all findings of noncompliance with NRC requirements and recommendations and results each audit to the Station Manager, Assistant Vice President and General Manager Nuclear Stations, Manger of Quality Assurance, Vice President of Nuclear Operations, and to the Executive Vice President of Construction, Production, and Engineering.

c. Authority

The Manager of Quality Assurance and the Supervisor of the Offsite Review and Investigative Function reports to the Chairman and President. Either the Manager of Quality Assurance or the Supervisor of the Offsite Review and Investigative Function has the authority to order unit shutdown or request any other action which he deems necessary to avoid unsafe plant conditions.

d. Records

1) Reviews, audits, and recommendations shall be documented and distributed as covered in 6.1.G.1.a and 6.1.G.1.b.

2) Copies of documentation, reports, and correspondence shall be kept on file at the station.

e. Procedures

Written administrative procedures shall be prepared and maintained for the offsite reviews and investigative functions described in Specifications 6.1.G.1.a. Those procedures shall cover the following:

1) Content and method of submission of presentations to the Supervisor of the Offsite Review and Investigative Function.

2) Use of committees and consultants.

3) Review and approval.

4) Detailed listing of items to be reviewed.

5) Method of (1) appointing personnel, (2) performing reviews, investigations, (3) reporting findings and recommendations of reviews and investigations, (4) approving reports, and (5) distributing reports.

6) Determining satisfactory completion of action required based on approved findings and recommendations reported by personnel performing the review and investigative function.

f. Personnel

1) The persons, including consultants, performing the review and investigative function, in addition to the Supervisor of the Offsite Review and Investigative Function, shall have expertise in one or more of the following disciplines as appropriate for the subject or subjects being reviewed and investigated:

a) nuclear power plant technology,
b) reactor operations,
c) utility operations,
d) power plant design,
e) reactor engineering,
f) radiological safety,
g) reactor safety analysis,
h) instrumentation and control,
i) metallurgy,
j) any other appropriate disciplines required by unique characteristics of the facility.

2) Individuals performing the Review and Investigative Function shall possess a minimum formal training and experience as listed below for each discipline.

a) Nuclear Power Plant Technology

Engineering graduate or equivalent with 5 years experience in the nuclear power field design and/or operations.

b) Reactor Operations

Engineering graduate or equivalent with 5 years experience in nuclear power plant operations.

c) Utility Operations

Engineering graduate or equivalent with at least 5 years of experience in utility operation and/or engineering.

d) Power Plant Design

Engineering graduate or equivalent with at least 5 years of experience in power plant design and/or operation.

e) Reactor Engineering

Engineering graduate or equivalent. In addition, at least 5 years of experience in nuclear plant engineering, operation, and/or graduate work in nuclear engineering or equivalent in reactor physics is required.

f) Radiological Safety

Engineering graduate or equivalent with at least 5 years of experience in radiation control and safety.

g) Reactor Safety Analysis

Engineering graduate or equivalent, with at least 5 years of experience in nuclear engineering.

h) Instrumentation and Control

Engineering graduate or equivalent with at least 5 years of experience in instrumentation and control design and/or operation.

i) Metallurgy

Engineering graduate or equivalent with at least 5 years of experience in the metallurgical field.

3) The Supervisor of the Offsite Review and Investigative Function shall have experience and training which satisfy ANSI N18.1-1971 requirements for plant managers.

2. The Onsite Review and Investigative Function shall be supervised by the Station Manager.

   a. Onsite Review and Investigative Function

      The Station Manager shall: (1) provide direction for the Review and Investigative Function and appoint the Technical Staff Supervisor, or other comparably qualified individual as a senior participant to provide appropriate directions; (2) approve participants for this function; (3) assure that a complement of more than one participant who collectively possess background and qualifications in the subject matter under review are selected to provide comprehensive interdisciplinary review coverage under this function; (4) independently review and approve the findings and recommendations developed by personnel performing the Review and Investigative Function; (5) report all findings of noncompliance with NRC requirements, and provide recommendations to the Assistant Vice President and General Manager Nuclear Stations and the Supervisor of the Offsite Review and Investigative Function; and (6) submit to the Offsite Review and Investigative Function concurrence in a timely manner, those items described in Specification 6.1.G.1.a which have been approved by the Onsite Review and Investigative Function. The responsibilities of the Personnel performing this function are stated below:

      1) Review of (1) procedures required by Specification 6.2 and changes thereto and (2) any other proposed procedures or changes thereto as determined by the Station Manager to affect nuclear safety.

      2) Review of all proposed tests and experiments that affect nuclear safety.

      3) Review of all proposed changes to the Technical Specifications.

      4) Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

      5) Investigation of all noncompliance with NRC requirements and shall prepare and forward a report covering evaluation and recommendations to prevent recurrence to the Assistant Vice President and General Manager Nuclear Stations and to the Supervisor of the Offsite Review and Investigative Function.

6) Review of facility operations to detect potential safety hazards.

7) Performance of special reviews and investigations and reports thereon as requested by the Supervisor of the Offsite Review and Investigative Function.

8) Review of the Station Security Plan and shall submit recommended changes to the Assistant Vice President and General Manager Nuclear Stations.

9) Review of the Emergency Plan and station implementing procedures and shall submit recommended changes to the Assistant Vice President and General Manager Nuclear Stations.

10) Review of reportable events and actions taken to prevent recurrence.

11) Review of any unplanned on-site release of radioactive material to the environs, including the preparation and forwarding of reports covering evaluation recommendations and disposition of the corrective action to prevent recurrence to the Assistant Vice President and General Manager Nuclear Stations, and to the Supervisor of the Offsite Review and Investigative Function.

12) Review of changes to the PCP and ODCM, and major changes to the radwaste treatment systems.

b. Authority

The Technical Staff Supervisor is responsible to the Station Manager and shall make recommendations in a timely manner in all areas of review, investigations, and quality control phases of plant maintenance, operation, and administrative procedures relating to facility operations and shall have the authority to request the action necessary to ensure compliance with rules, regulations, and procedures when in his opinion such action is necessary. The Station Manager shall follow such recommendations or select a course of action that is more conservative regarding safe operation of the facility. All such disagreements shall be reported immediately to the Assistant Vice President and General Manager Nuclear Stations and the Supervisor of the Offsite Review and Investigative Function.

c. Records

1) Reports, reviews, investigations, and recommendations shall be documented with copies to the Assistant Vice President and General Manager Nuclear Stations, the Supervisor of the Offsite Review and Investigative Function, the Station Manager, and the Manager of Quality Assurance.

2) Copies of all records and documentation shall be kept on file at the station.

d. Procedures

Written administrative procedures shall be prepared and maintained for conduct of the Onsite Review and Investigative function. These procedures shall include the following:

1) Content and method of submission and presentation to the Station Manager, Assistant Vice President and General Manager Nuclear Stations, and the Supervisor of the Offsite Review and Investigative Function.

2) Use of committees when necessary.

3) Review and approval.

4) Detailed listing of items to be reviewed.

5) Procedures for administration of the quality control activities.

6) Assignment of responsibilities.

e. Personnel

1) The personnel performing the Onsite Review and Investigative Function, in addition to the Station Manager, shall consist of persons having expertise in:

a) nuclear power plant technology,
b) reactor operations,
c) reactor engineering,
d) radiological safety and chemist,
e) instrumentation and control, and
f) mechanical and electric systems.

2) Personnel performing the Onsite Review and Investigative Function shall meet minimum acceptable levels as described in ANSI N18.1 1971, Sections 4.2 and 4.4.

H. Fire Protection Program

An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing either qualified offsite licensee personnel or an outside fire protection firm.

An inspection and audit of the fire protection and loss prevention program shall be performed by a qualified outside fire consultant at least once per 36 months.

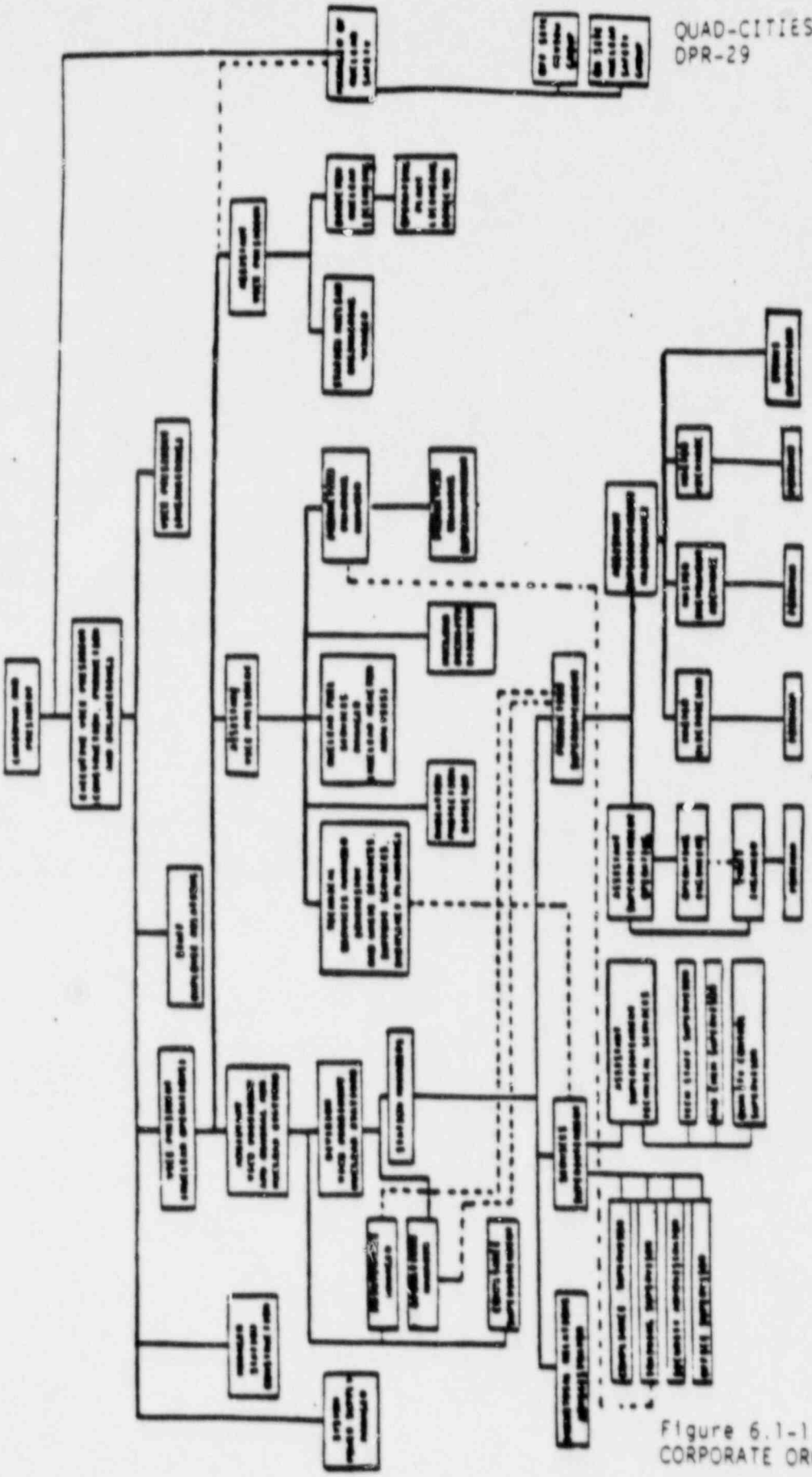
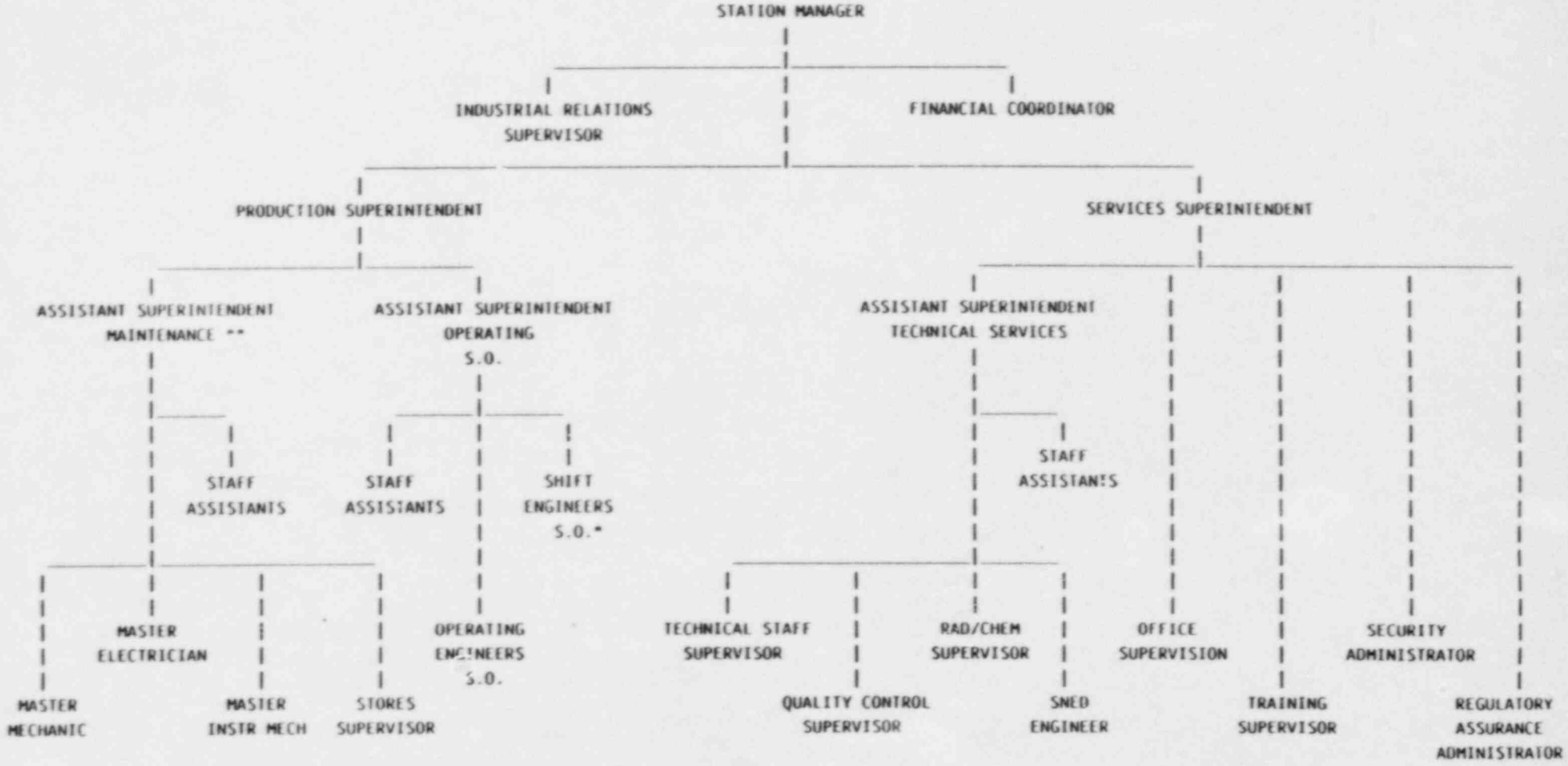


Figure 6.1-1
CORPORATE ORGANIZATION

0694B/0336Z

QUAD-CITIES
DPR-30



S.O. - Senior Operator's License
* - For number per shift, see "Shift Morning Chart", Figure 6.1-3
** - Responsible for implementing the Fire Protection Program

QUAD-CITIES STATION ORGANIZATION
FIGURE 6.1-2

MINIMUM SHIFT MANNING CHART#

License Category	CONDITION OF ONE UNIT (No Fuel in Second Unit)		
	Initial Fuel Loading or During Refueling	Cold Shutdown or Refueling Shutdown	Above Cold Shutdown
Senior Operator License	2	1	2
Operator License	2	2	3
Rad. Prot. Man	1	1	1
Non-Licensed	(As Required)	1	2
Shift Technical Advisor	None Required	None Required	1

License Category	CONDITION OF SECOND UNIT (One Unit at Hot Shutdown or at Power)		
	Initial Fuel Loading or During Refueling	Cold Shutdown or Refueling Shutdown	Above Cold Shutdown
Senior* Operator License	2	2	2
Operator* License	3	3	3
Rad. Prot. Man	1	1	1
Non-Licensed	3+ (As Required)	3	4
Shift Technical Advisor	1	1	1

License Category	CONDITION OF SECOND UNIT (One Unit at Cold Shutdown or Refueling Shutdown)		
	Initial Fuel Loading or During Refueling	Cold Shutdown or Refueling Shutdown	Above Cold Shutdown
Senior* Operator License	2	1	2
Operator* License	3	2	3
Rad. Prot. Man	1	1	1
Non-Licensed	3+ (As Required)	3	3
Shift Technical Advisor	None Required	None Required	1

* Assumes each individual is licensed on each facility. During initial fuel loading or during refueling, one senior engineer (limited license) will supervise fuel handling.

\# Shift crew composition may be less than the minimum requirements for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Figure 6.1-3.

Figure 6.1-3

6.2 PLANT OPERATING PROCEDURES

A. Detailed written procedures, including applicable checkoff lists covering items listed below shall be prepared, approved, and adhered to:

1. Normal startup, operation, and shutdown of the reactor, and other systems and components involving nuclear safety of the facility.

2. Refueling operations.

3. Actions to be taken to correct specific and foreseen potential malfunctions of systems or components, including responses to alarms, suspected primary system leaks, and abnormal reactivity changes.

4. Emergency conditions involving potential or actual release of radioactivity - "Generating Station Emergency Plan" and station emergency and abnormal procedures.

5. Instrumentation operation which could have an effect on the safety of the facility.

6. Preventive and corrective maintenance operations which could have an effect on the safety of the facility.

7. Surveillance and testing requirements.

8. Tests and experiments.

9. Procedure to ensure safe shutdown of the plant.

10. Station Security Plan and implementation procedures.

11. Fire Protection Program implementation.

12. ODCM implementation.

13. PCP implementation.

14. Working hours of the Shift Engineer, Station Control Room Engineer, Shift Foreman and the Nuclear Station Operator job classifications such that the heavy use of overtime is not routinely required.

6.2 PLANT OPERATING PROCEDURES

B. Radiation control procedures shall be maintained, made available to all station personnel, and adhered to. The procedures shall show permissible radiation exposure and shall be consistent with the requirements of 10 CFR 20. This radiation protection program shall be organized to meet the requirements of 10 CFR 20.

C. 1. Procedures for items identified in Specification 6.2.A and any changes to such procedures shall be reviewed and approved by the Operating Engineer and the Technical Staff Supervisor in the areas of operation or fuel handling and by Asst. Supt. Maintenance and Technical Staff Supervisor in the areas of plant maintenance and plant inspection. Procedures for items identified in Specification 6.2.B and any changes to such procedures shall be reviewed and approved by the Technical Staff Supervisor and the Radiation-Chemistry Supervisor. At least one person approving each of the above procedures shall hold a valid senior operator's license. In addition, these procedures and changes thereto must have authorization by a Station Superintendent before being implemented.

2. Work and instruction type procedures which implement approved maintenance or modification procedures shall be approved and authorized by the Asst. Supt. Maintenance where the written authority has been provided by a Station Superintendent. The "Maintenance Modification Procedure" utilized for safety related work shall be so approved only if procedures referenced in the "Maintenance Modification Procedure " have been approved as required by 6.2.A. Procedures which do not fall within the requirement of 6.2.A or 6.2.B may be approved by the Department Heads.

D. Temporary changes to procedures 6.2.A and 6.2.B above may be made provided:

1. The intent of the original procedure is not altered.

2. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's license on the unit affected.

3. The change is documented, reviewed on the On-Site Review and Investigative Function, and approved by the Station Manager within 14 days of implementation.

E. Drills of the emergency procedures described in Specification 6.2.A shall be conducted in accordance with the GSEP manual.

6.3 REPORTABLE EVENT ACTION

A. The following actions shall be taken for Reportable Events:

1. The Commission shall be notified and a report submitted pursuant to the requirements of Section 50.73 of 10CFR Part 50.

2. Each Reportable Event shall be reviewed by the On-Site Review Committee, and the results of this review shall be submitted to the Off-Site Review and Investigative Function and to the Assistant Vice President and General Manager, Nuclear Stations.

6.4 ACTION TO BE TAKEN IN THE EVENT A SAFETY LIMIT IS EXCEEDED

If a safety limit is exceeded, the reactor shall be shut down immediately, and reactor operation shall not be resumed until authorized by the NRC. The conditions of shutdown shall be promptly reported to the Assistant Vice President and General Manager Nuclear Stations or his designated alternate. The incident shall be reviewed pursuant to Specifications 6.1.G.1.a and 6.1.G.2.a and a separate report for each occurrence shall be prepared in accordance with Specification 6.3.A.1.

6.5 PLANT OPERATING RECORDS

A. Records and/or logs relative to the following items shall be kept in a manner convenient for review and shall be retained for at least 5 years:

1. Records of normal plant operation, including power levels and periods of operation at each power level;

2. Records of principal maintenance and activities, including inspection and repair, regarding principal items of equipment pertaining to nuclear safety;

3. Records and reports of reportable events and safety limit occurrences;

4. Records and periodic checks, inspection and/or calibrations performed to verify that the surveillance requirements (see Section 4 of these specifications) are being met (all equipment failing to meet surveillance requirements and the corrective action taken shall be recorded);

5. Records of changes made to the equipment or reviews of tests and experiments to comply with 10 CFR 50.59;

6. Records of radioactive shipments;

7. Records of physic tests and other tests pertaining to nuclear safety;

8. Records of changes to operating procedures;

9. Shift engineers' logs; and

10. Byproduct material inventory records and source leak test results.

B. Records and/or logs relative to the following items shall be recorded in a manner convenient for review and shall be retained for the life of the plant:

1. Bubstitution or replacement of principal items of equipment pertaining to nuclear safety;

2. Changes made to the plant as it is described in the SAR;

3. Records of new and spent fuel inventory and assembly histories;

4. Updated, corrected, and as-built drawings of the plant;

5. Records of plant radiation and contamination surveys;

6. Records of offsite environmental monitoring surveys;

7. Records of radiation exposure for all plant personnel, including all contractors and visitors to the plant, in accordance with 10 CFR 20;

8. Records of radioactivity in liquid and gaseous wastes released to the environment;

9. Records of transient or operational cycling for those components that have been designed to operate safely for a limited number of transient or operational cycles;

10. Records of individual staff members indicating qualifications, experience, training, and retraining;

11. Inservice inspections of the reactor coolant system;

12. Minutes of meetings and results of reviews and audits performed by the offsite and onsite review and audit functions; and

13. Records for Environmental Qualification which are covered under the provisions of paragraph 6.7.

6.6 REPORTING REQUIREMENTS

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following identified reports shall be submitted to the administrator of the appropriate Regional Office unless otherwise noted.

A. Routine Reports

1. 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 SAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

   Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the startup report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

2. A tabulation shall be submitted on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man rem exposure according to work and job function (Note: this tabulation supplements the requirements of Section 20.407 of 10 CFR 20), e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignments to various duty functions may be estimates based on pocket dosimeter, TLD, or film badge measurements. Small exposures totaling 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.

3. Monthly Operating Report

Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis to the Director, Office of Management Information and Program Control, U.S. Nuclear Regulatory Commission, Washington, DC 20555, with a copy to the appropriate Regional Office, to arrive no later than the 15th of each month following the calendar month covered by the report. In addition, any changes to the ODCM shall be submitted with the Monthly Operating Report within 90 days of the effective date of the change.

A report of major change to the radioactive waste treatment systems shall be submitted with the Monthly Operating Report for the period in which the evaluation was reviewed and accepted by the onsite review function. If such change is re-evaluated and not installed, notification of cancellation of the change should be provided to the NRC.

B. Unique Reporting Requirements

1. Radioactive Effluent Release Report (Semi-Annual)

A semi-annual report shall be submitted to the Commission within 60 days after January 1 and July 1 of each year specifying the quantity of each of the radionuclides released to unrestricted areas in liquid and gaseous effluents during the previous 6 months. The format and content of the report shall be in accordance with Regulatory Guide 1.21 (Revision 1) dated June, 1974. Any changes to the PCP shall be included in this report.

2. Environmental Program Data (Annual Report)

An annual report containing the data taken in the standard radiological monitoring program (Table 4.8-4) shall be submitted prior to May 1 of each year. The content of the report shall include:

a. Results of all environmental measurements summarized in the format of the Regulatory Guide 4.8 Table 1 (December 1975). (Individual sample results will be retained at the Station). In the event that some results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. Summaries, interpretations, and analysis of trends of the results are to be provided.

b. An assessment of the monitoring results and radiation dose via the principal pathways of exposure resulting from plant emissions of radioactivity including the maximum noble gas gamma and beta air doses in the unrestricted area. The assessment of radiation doses shall be performed in accordance with the Offsite Dose Calculation Manual (ODCM).

c. Results of the census to determine the locations of nearest residences and of nearby animals producing milk for human consumption.

(Table 4.8-4).

d. The reason for the omission if the nearest dairy to the station is not in the monitoring program (Table 4.8-4).

e. An annual summary of meteorological conditions concurrent with the releases of gaseous effluents in the form of joint frequency distributions of wind speed, wind direction, and atmospheric stability.

f. The results of the Interlaboratory Comparison Program described in section 3.8.D.7.

g. The results of the 40 CFR 190 uranium fuel cycle dose analysis for each calendar year

h. A summary of the monitoring program, including maps showing sampling locations and tables giving distance and direction of sampling locations from the Station.

3. If a confirmed measured radionuclide concentration in an environmental sampling medium averaged over any calendar quarter sampling period exceeds the reporting level given in Table 4.8-5 and if the radioactivity is attributable to plant operation, a written report shall be submitted to the Administrator of the NRC Regional Office, with a copy to the Director, Office of Nuclear Reactor Regulation, within 30 days from the end of the quarter.

a. When more than one of the radionuclides in Table 4.8-5 are detected in the medium, the reporting level shall have been exceeded if

$$\sum \frac{Ci}{R.L.i} \geq 1$$

where Ci is the average quarterly concentration of the ith radionuclide in the medium and RL is the reporting level of radionuclide i.

b. If radionuclides other than those in Table 4.8-5 are detected and are due to plant effluents, a reporting level is exceeded if the potential annual dose to an individual is equal to or greater than the design objective doses of 10 CFR 50, Appendix I.

c. This report shall include an evaluation of any release conditions, environmental factors, or other aspects necessary to explain the anomalous effect.

4. Special Reports

Special Reports shall be submitted as indicated in Table 6.6-1.

TABLE 6.6-1
SPECIAL REPORTS

	Area	Specification Reference	Submittal Date
a.	Secondary containment leak rate test (1)	4.7.C	Upon completion of each test.
b.	Summary status of fuel performance	1.1 Bases	After each refueling outage.
c.	Materials radiation surveillance specimens	4.6.B.2	after each specimen removal and completion of analyses.
d.	Radioactive Source Leak Testing (2)	4.8.F	Annual Report
e.	Special Effluents Reports	3.8.A 3.8.B 3.8.D 6.6.C.3.	30 days following occurrence.

Notes

1. Each integrated leak rate test of the secondary containment shall be the subject of a summary technical report. This report should include data on the wind speed, wind direction, outside and inside temperatures during the test, concurrent reactor building pressure, and emergency ventilation flow rate. The report shall also include analyses and interpretations of those data which demonstrate compliance with the specified leak rate limits.

2. This report is required only if the tests reveal the presence of the 0.005 microcuries or more of removable contamination.

6.7 ENVIRONMENTAL QUALIFICATION

A. All safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: Assistant 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-29 dated October 24, 1980.

B. Complete and auditable 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. Such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.8 OFFSITE DOSE CALCULATION MANUAL (ODCM)

A. The ODCM shall describe the methodology and parameters to be used in the calculation of offsite doses due to radioactive gaseous and liquid effluents and in the calculation of gaseous and liquid effluent monitoring instrumentation alarm/trip setpoints consistent with the applicable LCO's contained in these Technical Specifications. Methodologies and calculational procedures acceptable to the Commission are contained in NUREG-0133.

The ODCM shall be submitted to the Commission at the time of proposed Radiological Effluent Technical Specifications and shall be subject to review and approval by the Commission prior to implementation.

B. Licensee initiated changes to the ODCM may be made provided the change:

1. Shall be submitted to the Commission by inclusion in the Monthly Operating Report pursuant to Specification 6.6.A.3. within 90 days of the date the change(s) was made effective and shall contain:

   a. Sufficiently detailed information to support the change. Information submitted should consist of a package of those pages of the ODCM to be changed together with appropriate analyses or evaluations justifying the change(s);

   b. A determination that the change will not reduce the accuracy of reliability of dose calculations or setpoint determinations; and

   c. Documentation of the fact that the change has been reviewed and found acceptable by the onsite review functions.

2. Shall become effective upon review and acceptance by the onsite review function.

6.9 PROCESS CONTROL PROGRAM (PCP)

A. The PCP shall contain the sampling, analysis, and formulation determination by which solidification of radioactive wastes from liquid systems is assured.

B. The PCP shall be approved by the Commission prior to implementation.

C. Licensee initiated changes may be made to the PCP provided the change:

1. Shall be submitted to the Commission in the Radioactive Effluent Release Report for the period in which the change was made and shall contain:

   a. Sufficiently detailed information to support the change;

   b. A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

   c. Documentation that the change has been reviewed and found acceptable by the onsite review function.

2. Shall become effective upon review and acceptance by the onsite review function.

6.10 MAJOR CHANGES TO RADIOACTIVE WASTE TREATMENT SYSTEMS (LIQUID, GASEOUS, SOLID)

A. Licensee initiated major changes to the radioactive waste systems may be made provided:

1. The change is reported in the Monthly Operating Report for the period in which the evaluation was reviewed by the onsite review function. The discussion of each change shall contain:

   a. A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR 50.59;

   b. Sufficient detailed information to support the reason for the change;

   c. A detailed description of the equipment, components, and process involved and the interfaces with other plant systems;

   d. An evaluation of the change which shows the predicted releases of radioactive materials in liquid and gaseous effluents and (or quantity of solid waste that differ from those previously predicted in the license application and amendments);

   e. A comparison of the predicted releases of radioactive materials in liquid and gaseous effluents and in solid waste to the actual releases for the period in which the changes were made;

   f. An estimate of the exposure to plant operating personnel as a result of the change; and

   g. Documentation of the fact that the change was reviewed and found acceptable by the onsite review function.

2. The change shall become effective upon review and acceptance by onsite review function.

APPENDIX B

TO FACILITY OPERATING LICENSE NO. DPR-29

QUAD CITIES STATION

UNIT 1

COMMONWEALTH EDISON COMPANY

DOCKET NO. 50-254

ENVIRONMENTAL PROTECTION PLAN

(NON-RADIOLOGICAL)

TECHNICAL SPECIFICATION PAGE INDEX

08/06/82

Quad Cities Station Unit 1 Nuclear Operating License No. DPR-29

Page	Original Sheet	Amendment No.	Date
Appendix B Title Sheet		81	8/06/82
1-1		81	8/06/82
2-1		81	8/06/82
2-2		81	8/06/82
2-3		81	8/06/82
3-1		81	8/06/82

1.0 Objectives of the Environmental Protection Plan

The Environmental Protection Plan (EPP) is to provide for protection of environmental values during construction and operation of the nuclear facility. The principal objectives of the EPP are as follows:

(1) Verify that the plant is operated in an environmentally acceptable manner, as established by the FES and other NRC environmental impact assessments.

(2) Coordinate NRC requirements and maintain consistency with other Federal, State and local requirements for environmental protection.

(3) Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects.

Environmental concerns identified in the FES which relate to water quality matters are regulated by way of the licensee's National Pollutant Discharge Elimination (NPDES) permit, issued by the Illinois Environmental Protection Agency.

2.0 Consistency Requirements

2.1 Plant Design and Operation

The licensee may make changes in station design or operation or perform tests or experiments affecting the environment provided such changes, tests or experiments do not involve an unreviewed environmental question. Changes in plant design or operation or performance of tests or experiments which do not affect the environment are not subject to this requirement. Activities governed by Section 2.3 are not subject to the requirements of this section.

Before engaging in unauthorized construction or operational activities which may affect the environment, the licensee shall prepare and record an environmental evaluation of such activity.* When the evaluation indicates that such activity involves an unreviewed environmental question, the licensee shall provide a written evaluation of such activities and obtain prior approval from the NRC.

A proposed change, test or experiment shall be deemed to involve an unreviewed environmental question if it concerns (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the final environmental statement (FES) as modified by staff's testimony to the Atomic Safety and Licensing Board, supplements to the FES, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or (2) a significant change in effluents or power level (in accordance with 10 CFR Part 51.5(b)(2)) or (3) a matter not previously reviewed and evaluated in the documents specified in (1) of this Subsection, which may have significant adverse environmental impact.

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*Activities are excluded from this requirement if all measurable nonradiological effects are confined to the on-site areas previously disturbed during site preparation and plant construction.

The licensee shall maintain records of changes in facility design or operation and of tests and experiments carried out pursuant to this Subsection. These records shall include a written evaluation which provide bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question.

2.2 Reporting Related to the NPDES Permits and State Certifications

Violations of the NPDES Permit or the State certification (pursuant to Section 401 of the Clean Water Act) shall be reported to the NRC by submittal of copies of the reports required by the NPDES Permit or certification. The licensee shall also provide the NRC with copies of the results of environmental studies at the same time they are submitted to the permitting agency. Changes and additions to the NPDES Permit or the State certification shall be reported to the NRC within 30 days following the date the change is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

The NRC shall be notified of changes to the effective NPDES Permit proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The licensee shall provide the NRC a copy of the application for renewal of the NPDES Permit at the same time the application is submitted to the permitting agency.

2.3 Changes Required for Compliance with Other Environmental Regulations

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with other Federal, State, or local environmental regulations are not subject to the requirements of Section 2.1.

3.0 Environmental Conditions

3.1 Unusual or Important Environmental Events

Any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to station operation shall be recorded and promptly reported to the NRC within 24 hours followed by a written report within 30 days. No routine monitoring programs are required to implement this condition.

The written report shall (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact and plant operating characteristics, (b) describe the probable cause of the event, (c) indicate the action taken to correct the reported event, (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems, and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided a copy of such report at the same time it is submitted to the other agency.

The following are examples of unusual or important events: excessive bird impaction events; onsite plant or animal disease outbreaks; mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973; unusual fish kills; increase in nuisance organisms or conditions; and unanticipated or emergency discharge of waste water or chemical substances.

ATTACHMENT 2

SUMMARY OF CHANGES

TOTAL NUMBER OF PAGES LIST

SECTION	CURRENT	RETYPED
Operating License	7	6
Table of Contents	vi	vii
Index (Page)	9	not created
Definitions	5	6
1.1/2.1	11 plus 2 figures	17 plus 2 figures
1.2/2.2	3	4
3.0/4.0	3	2
3.1/4.1	14 plus 1 figure	17 plus 1 figure
3.2/4.2	20 plus 1 figure	35 including figure
3.3/4.3	11	17
3.4/4.4	3 plus 2 figures	5 plus 2 figures
3.5/4.5	19 plus 5 figures	26 plus 6 figures
3.6/4.6	21 plus 2 figures	45 including 3 figures
3.7/4.7	23	39
3.8/4.8	30 including 1 figure	39 including 1 figure
3.9/4.9	6	12
3.10/4.10	6	10
3.11/4.11	3	3
3.12/4.12	9	13
5.0	1	2
6.1	6 plus 3 figures	11 plus 3 figures
6.2	1	2
6.3	1	1
6.4	1	1
6.5	1	2
6.6	5	5
6.7	1	1
6.8	1	1
6.9	1	1
6.10	1	1
Appendix B		
1.0	1	1
2.0	3	3
3.0	1	1

1127H/0384Z/

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
3	asociated	3	associated	SPELLING
3	Cites	3	Cities	SPELLING
iii	Action to be Taken in the Event of a Reportable Occurrence in Plant Operation.	iv	Reportable Event Action	ACCURACY
vi	and	vii	an	SPELLING
vi	k	vii	k_f	ACCURACY
vi		vii	3.6-2 Minimum Reactor Pressurization Temperature	ACCURACY
1.0-2	RMB	1.0-2	RBM	SPELLING
1.0-5	titles underlined/ capitalized	1.0-6	titles not underlined or capitalized	CONSISTENCY
1.1/2.1-2	startup or run	1.1/2.1-3	Startup or Run	CLARITY
1.1/2.1-2a	Bases 3.2)	1.1/2.1-4	Bases 3.2).	GRAMMAR
1.1/2.1-10	Isolation to Valve	1.1/2.1-15	Isolation Valve	ACCURACY
1.1/2.1-10	lost	1.1/2.1-16	loss	GRAMMAR
1.1/2.1-10	vacuum stop	1.1/2.1-16	vacuum, stop	GRAMMAR
1.1/2.1-11	Reactors" General	1.1/2.1-17	Reactors", General	CLARITY
1.1/2.1-2	USAS1	1.2/2.2-2	USASI	ACCURACY
3.1/4.1-2	and	3.1/4.1-3	an	GRAMMAR
3.1/4.1-3	SAP	3.1/4.1-5	SAR	ACCURACY
3.1/4.1-3	modes in addition,	3.1/4.1-5	modes. In addition,	CLARITY
3.1/4.1-7	is	3.1/4.1-10	in	GRAMMAR
3.1/4.1-11	shroud 1	3.1/4.1/14	shroud. 1	CLARITY
3.2/4.2-3	streamline	3.2/4.2-3	steamline	SPELLING
3.2/4.2-5a	initiates	3.2/4.2-6	initiate	GRAMMAR
3.2/4.2-5a	CONDITION	3.2/4.2-6	CONDITIONS	ACCURACY

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
3.2/4.2-5a	subsystems starts	3.2/4.2-7	subsystems, starts	CLARITY
3.2/4.2-5a	also Group	3.2/4.2-7	also. Group	CLARITY
3.2/4.2-8	streamline	3.2/4.2-11	steamline	SPELLING
3.2/4.2-10	Figure 4.2-2	3.2/4.2-13	Figure 4.2-1	ACCURACY
3.2/4.2-11	Hot Shutdown	3.2/4.2-16	Hot Standby	ACCURACY
3.2/4.2-12	SGTS	3.2/4.2-17	SBGTS	ACCURACY
3.2/4.2-12	presure	3.2/4.2-18	pressure	SPELLING
3.2/4.2-12	buses	3.2/4.2-18	buses.	CONSISTENCY
3.2/4.2-13	(5)	3.2/4.2-18	[5]	CONSISTENCY
3.2/4.2-14	NOTE ID #'s in paren.	3.2/4.2-19	NOTE ID #'s bracketed	CONSISTENCY
3.2/4.2-14	Notes	3.2/4.2-20	<u>Notes</u>	CLARITY
3.2/4.2-14	GT/E	3.2/4.2-20	≥	CLARITY
3.2/4.2-15	Note ID #'s in paren.	3.2/4.2-21	Note ID #'s bracketed	CONSISTENCY
3.2/4.2-15	{	3.2/4.2-21	[	CLARITY
3.2/4.2-15	{ (twice)	3.2/4.2-22	[	CLARITY
3.2/4.2/15b	(1)	3.2/4.2-24	[1]	CONSISTENCY
3.2/4.2-15c	(2)	3.2/4.2-25	[2]	CONSISTENCY
3.2/4.2-18	{ (twice)	3.2/4.2-30	[	CLARITY
3.2/4.2-18a	{	3.2/4.2-31	[	CLARITY
3.2/4.2-19	failure	3.2/4.2-32	failure.	CONSISTENCY
3.3/4.3-7	other	3.3/4.3-9	others	GRAMMAR
3.3/4.3-7	inset	3.3/4.3-9	insert	SPELLING
3.3/4.3-7	collect	3.3/4.3-10	collet	SPELLING

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
3.3/4.3-7	the	3.3/4.3-10	be	SPELLING
3.4/4.4-3	3470	3.4/4.4-4	3,470	ACCURACY
3.4/4.4-3	4875	3.4/4.4-4	4,875	ACCURACY
3.5/4.5-3	test.	3.5/4.5-4	test	CONSISTENCY
3.5/4.5-3	outage.	3.5/4.5-4	outage	CONSISTENCY
3.5/4.5-9	in	3.5/4.5-13	to	GRAMMAR
3.5/4.5-10	3.5.2	3.5/4.5-14	3.5-2	ACCURACY
3.5/4.5-11	CONDITION	3.5/4.5-15	CONDITIONS	ACCURACY
3.5/4.5-11	Conditions	3.5/4.5-15	conditions	CLARITY
3.5/4.5-11	additional	3.5/4.5-15	additionally	GRAMMAR
3.5/4.5-12	subsystems	3.5/3.5-17	subsystem	ACCURACY
3.5/4.5-14	assues	3.5/4.5-20	assures	SPELLING
3.5/4.5-16	period caused	3.5/4.5-23	period is caused	CLARITY
3.5/4.5-18	fail	3.5/4.5-25	fails	GRAMMAR
3.6/4.6-2	3.6.1 (twice)	3.6/4.6-2	3.6-1	ACCURACY
3.6/4.6-2	lossened	3.6/4.6-3	loosened	SPELLING
3.6/4.6-4a	flow	3.6/4.6-8	flaw	SPELLING
3.6/4.6-5a	excedes	3.6/3.6-12	exceeds	SPELLING
3.6/4.6-5a	UPSCALE (twice)	3.6/4.6-12	Upscale (twice)	CONSISTENCY
3.6/4.6-5a	1 (twice)	3.6/4.6-13	I	ACCURACY
3.6/4.6-5b	3.6.1.2	3.6/4.6-12	3.6.I.2	ACCURACY
3.6/4.6-5b	4.6.1.2	3.6/4.6-12	4.6.I.2	ACCURACY
3.6/4.6-7	4.6.1.5.a	3.6/4.6-14	4.6.I.5.a	ACCURACY

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
3.6/4.6-8	3.6.1	3.6/4.6-17	3.6-1	ACCURACY
3.6/4.6-9	3.6.1	3.6/4.6-17	3.6-1	ACCURACY
3.6/4.6-9	4.6.2	3.6/4.6-17	4.6-2	ACCURACY
3.6/4.6-12	Code. Rules for	3.6/4.6-22	Code, Rules for	ACCURACY
3.6/4.6-15b	stream (twice)	3.6/4.6-28	steam	SPELLING
3.6/4.6-15c	stream (twice)	3.6/4.6-29	steam	SPELLING
3.6/4.6-15g	Fig. 3.6.1	3.6/4.6-33	Fig. 3.6-1	ACCURACY
3.6/4.6-17	at once	3.6/4.6-35	at least once	CLARITY
3.6/4.6-19	20-in	3.6/4.6-38	20-in.	CONSISTENCY
3.6/4.6-21	Line Group	3.6/4.6-41	Line-Group	CONSISTENCY
3.6/4.6-21a	Table 4.6.2	3.6/4.6-43	Table 4.6-2	ACCURACY
NO PAGE DESIGNATED	3.6-1	3.6/4.6-44	3.6-2	ACCURACY
3.7/4.7-2	cool-down	3.7/4.7-2	cooldown	CLARITY
3.7/4.7-2	Submergence (twice)	3.7/4.7-2	submergence	CLARITY
3.7/4.7-4	MO1-220-2 MO	3.7/4.7-5	MO1-220-2, MO	CLARITY
3.7/4.7-6	pressure-suppression	3.7/4.7-8	pressure suppression	ACCURACY
3.7/4.7-6a	3.7.A.5(b)	3.7/4.7-11	3.7.A.5.b	ACCURACY
3.7/4.7-7	7.	3.7/4.7-12	deleted	NOT REQUIRED
3.7/4.7-7a	(±10% on	3.7/4.7-13	(±10%) on	ACCURACY
3.7/4.7-7b	maintence	3.7/4.7-14	maintenance	SPELLING
3.7/4.7-7b	(±10% on	3.7/4.7-14	(±10%) on	ACCURACY
3.7/4.7-7b	1. Postmaintenance	3.7/4.7-14	3. Postmaintenance	ACCURACY

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
3.7/4.7-7c	particulates	3.7/4.7-16	particulate	GRAMMAR
3.7/4.7-11	changes	3.7/4.7-21	chances	ACCURACY
3.7/4.7-11	control worth	3.7/4.7-21	control rod worth	CLARITY
3.7/4.7-11	adsorb	3.7/4.7-21	absorb	ACCURACY
3.7/4.7-11	minimum of	3.7/4.7-21	minimum or	SPELLING
3.7/4.7-13 & 14	The Laboratory	3.7/4.7-25	The charcoal...Laboratory	INADVERTENTLY REMOVED WHEN AMENDMENT 96 WAS ISSUED.
3.7/4.7-14	"Quad...Analyses"	3.7/4.7-26	'Quad...Analyses'	CONSISTENCY
3.7/4.7-17	Closed to	3.7/4.7-30	closed to	ACCURACY
3.7/4.7-17	circum-ference	3.7/4.7-30	circumference	SPELLING
3.7/4.7-20	(min.) (twice)	3.7/4.7-33	deleted	CONSISTENCY
3.7/4.7-22	Steamline	3.7/4.7-38	steamline	CONSISTENCY
3.7/4.7-33	(sec.) (twice)		deleted	CONSISTENCY
3.8/4.8-1	measurements radioactive	3.8/4.8-1	measurements of radioactive	GRAMMAR
3.8/4.8-6	3.8.H	3.8/4.8-8	3.8.A.7	ACCURACY
3.8/4.8-6	31 days:	3.8/4.8-8	31 days,	ACCURACY
3.8/4.8-9	vacuum shall	3.8/4.8-13	vacuum pump shall	ACCURACY
3.8/4.8-11	report	3.8/4.8-15	Report	CONSISTENCY
3.8/4.8-12	with 30 days	3.8/4.8-16	within 30 days	ACCURACY
3.8/4.8-14a	absorbers	3.8/4.8-19	adsorbers	ACCURACY
3.8/4.8-14a	2.	3.8/4.8-20	2)	CONSISTENCY
3.8/4.8-14a	absorber	3.8/4.8-20	adsorber	ACCURACY
3.8/4.8-14b	absorber	3.8/4.8-20	adsorber	ACCURACY

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
3.8/4.8-14b	absorber (twice)	3.8/4.8-21	adsorber	ACCURACY
3.8/4.8-15	no title	3.8/4.8-22	Title added	CLARITY
3.8/4.8-16	3.8/4.8.A.5.	3.8/4.8-24	3.8/4.8.A.5	CONSISTENCY
3.8/4.8-17	3.8/4.8.B.2	3.8/4.8-24	3.8/4.8.B.2	CONSISTENCY
3.8/4.8-17	Section II.A. of	3.8/4.8-24	Section II. A of	CONSISTENCY
3.8/4.8-18	3.8/4.8.D.1	3.8/4.8-25	3.8/4.8.D.1	CONSISTENCY
3.8/4.8-18	3.8/4.8.D.6	3.8/4.8-25	3.8/4.8.D.6	CONSISTENCY
3.8/4.8-18	liter/year	3.8/4.8-25	liters/year	GRAMMAR
3.8/4.8-18	3.8/4.8.D.7	3.8/4.8-26	3.8/4.8.D.7	CONSISTENCY
3.8/4.8-19	3.8/4.8.C.	3.8/4.8-26	3.8/4.8.C	CONSISTENCY
3.8/4.8-19	3.8/4.8.E.	3.8/4.8-26	3.8/4.8.E	CONSISTENCY
3.8/4.8-19	3.8/4.8.F.	3.8/4.8-26	3.8/4.8.F	CONSISTENCY
3.8/4.8-19	section F preceded E	3.8/4.8-26	section E precedes F	CLARITY
3.8/4.8-19	filtrations unit	3.8/4.8-26	filtration unit	ACCURACY
3.8/4.8-20	title not underlined	3.8/4.8-27	title underlined	CONSISTENCY
3.8/4.8-20	uci	3.8/4.8-27	µCi	ACCURACY
3.8/4.8-20	SR(twice)	3.8/4.8-27	Sr	ACCURACY
3.8/4.8-21a	uCl/ml	3.8/4.8-29	µCi/ml	ACCURACY
3.8/4.8-21a	abd	3.8/4.8-29	and	SPELLING
3.8/4.8-22	Table 4.8-3	3.8/4.8-30	Table 4.8-3	CONSISTENCY
3.8/4.8-22	uci/ml	3.8/4.8-30	µCi/ml	ACCURACY
3.8/4.8-24	Table 4.8-4	3.8/4.8-32	Table 4.8-4	CONSISTENCY
3.8/4.8-24	column titles completely underlined	3.8/4.8-32	column titles not completely underlined	ACCURACY

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PAGE	CURRENT	PAGE	RETYPED	REASON
3.8/4.8-25	column titles completely underlined	3.8/4.8-33	column titles not completely underlined	ACCURACY
3.8/4.8-26	column titles completely underlined	3.8/4.8-34	column titles not completely underlined	ACCURACY
3.8/4.8-27	Table 4.8-5	3.8/4.8-35	Table 4.8-5	CONSISTENCY
3.8/4.8-28	Titles not underlined	3.8/4.8-36	Title Underlined	CONSISTENCY
3.8/4.8-30	Figure 4.8.1	3.8/4.8-39	Figure 4.8-1	CONSISTENCY
3.9/4.9-2	cells to	3.9/4.9-3	cell to	GRAMMAR
3.12/4.12-1	3.12-1;	3.12/4.12-1	3.12-1:	CONSISTENCY
3.12/4.12-2	times with;	3.12/4.12-2	times with:	CONSISTENCY
3.12/4.12-2	24 hours;	3.12/4.12-4	24 hours:	CONSISTENCY
3.12/4.12-3	back up fire	3.12/4.12-5	backup fire	ACCURACY
3.12/4.12-4	stand by level	3.12/4.12-5	standby level	ACCURACY
3.12/4.12-4	Table 3.12.3	3.12/4.12-6	Table 3.12-3	ACCURACY
3.12/4.12-4	barrier	3.12/4.12-7	barriers	GRAMMAR
3.12/4.12-4	inspection;	3.12/4.12-7	inspection:	CONSISTENCY
3.12/4.12-5	verifying;	3.12/4.12-9	verifying:	CONSISTENCY
3.12/4.12-6	CONDITION	3.12/4.12-10	CONDITIONS	ACCURACY
3.12/4.12-6	REQUIREMENT	3.12/4.12-10	REQUIREMENTS	ACCURACY
5.0-1	Titles not capitalized nor underlined	5.0-1 & 2	Titles capitalized and underlined	FORMAT
6.1-1	ADMINISRATIVE	6.1-1	ADMINISTRATIVE	SPELLING
6.1-1	a least	6.1-1	at least	SPELLING
6.1-1	5 member	6.1-1	5 members	GRAMMAR
6.1-1	supervisor	6.1-1	Supervisor	CONSISTENCY
6.1-2	shall (1)	6.1-2	shall: (1)	CONSISTENCY
6.1-2	posses	6.1-2	possess	SPELLING

TABLE OF CHANGES

PAGE	CURRENT	PAGE	RETYPED	REASON
6.1-2	function (4)	6.1-2	function, (4)	CONSISTENCY
6.1-3	at Least	6.1-4	at least	CLARITY
6.1-5	directions,	6.1-8	directions;	CONSISTENCY
6.1-5	posses	6.1-8	possess	SPELLING
6.1-5	investigative	6.1-8	Investigative	CONSISTENCY
6.1-6	area of	6.1-9	areas of	GRAMMAR
6.1-6	Manager shall	6.1-10	Manager, shall	GRAMMAR
6.2-1	6.2-A	6.2-2	6.2.A	ACCURACY
6.3-1	6.2.A.	6.2-2	6.2.A	CONSISTENCY
6.5-1	years.	6.5-1	years:	CONSISTENCY
6.5-1	plant.	6.5-1	plant:	CONSISTENCY
6.5-1	all items followed by periods or colons	6.5-1 & 2	all items followed by semi-colons	CONSISTENCY
6.6-2	station utility	6.6-1	station, utility	CLARITY
6.6-2	report	6.6-2	reports	GRAMMAR
6.6-3	As assessment	6.6-3	An assessment	GRAMMAR
6.8-1	title not capitalized	6.8-1	title capitalized	CONSISTENCY
6.9-1	title not capitalized	6.9-1	title capitalized	CONSISTENCY
6.10-1	title not capitalized but underlined	6.10-1	title capitalized and not underlined.	CONSISTENCY

ATTACHMENT 3

BASIS FOR SIGNIFICANT HAZARDS CONSIDERATION
Retype of the Quad Cities Unit 1 Tech Specs, Appendix A to DPR-29, pps i thru 3-1, inclusive

To improve the clarity of the Quad Cities Unit 1 Technical Specifications, they have been retyped and Commonwealth Edison requests that they be reissued in their enterity as an amendment to Facility operating License DPR-29.

The retyped Unit one Technical Specifications involve such changes as those made to improve grammar, correct typographical errors, and improve the legibility of the current specifications. Additionally, the Unit 1 retype is able to benefit from todays improved Word Processor capability.

Attachment 2 identifies all changes made (due to spelling, grammar, clarity, consistency, accuracy and improved word processor capability) to the retyped Technical Specifications. The attachment also identifies the changes made to the page number designations of each section of the specifications as a result of the retype. The number of pages in each section is now different because of the utilization of a word processing system to retype the Technical Specifications.

No changes have been made which are technical in nature; as a result, the amendment may be considered to be administrative in nature.

These changes have been reviewed by Commonwealth Edison and we believe that they do not present a Significant Hazards Consideration. The basis for our determination is documented as follows:

BASIS FOR NO SIGNIFICANT HAZARDS CONSIDERATION

Commonwealth Edison has evaluated this proposed amendment and determined that it involves no significant hazards consideration. In accordance with the criteria of 10 CFR 50.92(c), a proposed amendment to an operating license involves no significant hazards considerations if operation of the facility, in accordance with the proposed amendment, would not:

1) Involve a significant increase in the probability or consequences of an accident previously evaluated because:

   (a) This amendment does not change the content of the current approved Technical Specifications. This amendment is administrative in nature and is merely sought to improve the clarity and legibility of the Unit 1 Technical Specifications.

Therefore, these changes do not significantly increase the probability increase the probability or consequences of previously evaluated accidents.

2) Create the possibility of a new or different kind of accident from any accident previously evaluated because:

   (a) The proposed amendment contains no content changes of currently approved Unit 1 DPR-29 Technical Specifications. An administrative change does not create the possibility of a new or different kind of accident from any previously evaluated.

3) Involve a significant reduction in the margin of safety because:

   (a) The proposed amendment is merely a retyped version of the current, NRC approved Unit One DPR-29 Technical Specifications. There are no technical changes associated with this amendment and it is considered to be administrative in nature. Therefore, the margin of safety is unaffected as a result of this change.

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