Exelon Generation.

200 Exelon Way
Kennett Square, PA 19348

www.exeloncorp.com

TS 6.8.4.h.d

LG-16-054
April 14, 2016

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Limerick Generating Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Submittal of Changes to Technical Specifications Bases

In accordance with the requirement of Limerick Generating Station (LGS), Units 1 and 2 Technical Specification 6.8.4.h.d, Exelon Generation Company, LLC, hereby submits a complete updated copy of the Unit 1 and Unit 2 Technical Specifications Bases, which includes changes through the date of this letter.

If you have any questions or require further information, please contact Stephanie J. Hanson at 610-765-5143.

Sincerely,

James Barstow

James Barstow
Director, Licensing & Regulatory Affairs
Exelon Generation Company, LLC

Enclosures: 1) LGS Unit 1 Technical Specifications Bases
2) LGS Unit 2 Technical Specifications Bases

cc: USNRC Region I, Regional Administrator (w/o enclosures)
USNRC Senior Resident Inspector, LGS (w/o enclosures)
USNRC Senior Project Manager, LGS (w/o enclosures)
R. R. Janati, Bureau of Radiation Protection (w/o enclosures)

A001
NRR

License No. NPF-39

Limerick Generating Station, Unit No. 1

Docket No. 50-352

Issued by the
U.S. Nuclear Regulatory
Commission

Office of Nuclear Reactor Regulation

BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

AUG 8 1985

INTENTIONALLY LEFT BLANK

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

AUG 8 1985

3890020620

THIS PAGE INTENTIONALLY LEFT BLANK

 3891002560

Specifications 3.0.1 through 3.0.4 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

> "Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. It is not intended that the shutdown ACTION requirement be used as an operational convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

3/4.0 APPLICABILITY

BASES

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routine) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in COLD SHUTDOWN when a shutdown is required during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is required, the time limit for reaching the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if STARTUP is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower CONDITION of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered permit continued operation in the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time. Compliance with ACTION requirements that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made in accordance with the provisions of the ACTION requirements.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk

assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified

conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONs. The sole purpose of this Specification is to provide an exception to Specifications 3.0.1 and 3.0.2 (e.g., to not comply with the applicable ACTION(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service, or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONs is limited to the time necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with required ACTIONs and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

Specification 3.0.6 establishes an exception to Specifications 3.0.1 and 3.0.2 for supported systems that have a support system Limiting Condition for Operation specified in the Technical Specifications (TS). The exception to Specification 3.0.1 is provided because Specification 3.0.1 would require that the ACTIONs of the associated inoperable supported system Limiting Condition for Operation be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system Limiting Condition for Operation's ACTIONs. These ACTIONs may include entering the supported system's ACTIONs or may specify other ACTIONs. The exception to Specification 3.0.2 is provided because Specification 3.0.2 would consider not entering into the ACTIONs for the supported system within the specified time intervals as a TS noncompliance.

When a support system is inoperable and there is a Limiting Condition for Operation specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' ACTIONs unless directed to do so by the support system's ACTIONs. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Limiting Condition for Operations' ACTIONs are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's ACTIONs.

However, there are instances where a support system's ACTION may either direct a supported system to be declared inoperable or direct entry into ACTIONS for the supported system. This may occur immediately or after some specified delay to perform some other ACTION. Regardless of whether it is immediate or after some delay, when a support system's ACTION directs a supported system to be declared inoperable or directs entry into ACTIONs for a supported system, the applicable ACTIONs shall be entered in accordance with Specification 3.0.1.

Specification 6.17, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into Specification 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system ACTIONs. The SFDP implements the requirements of Specification 3.0.6.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

EXAMPLE B 3.0.6-1
If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

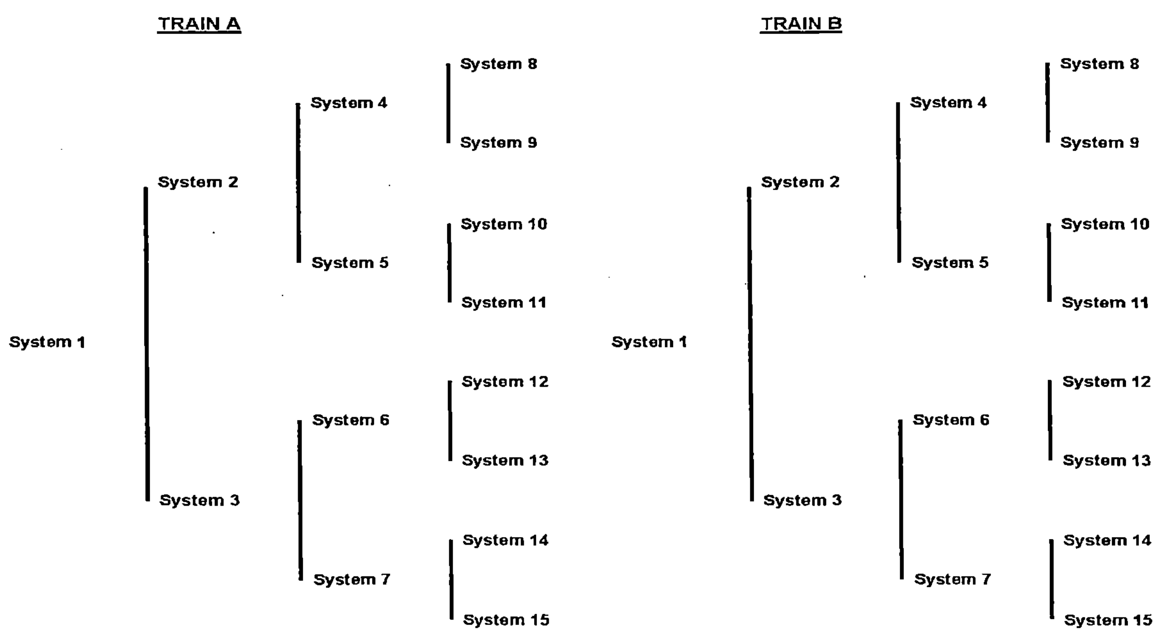


Figure B 3.0-1
Configuration of Trains and Systems

If an evaluation determines that a loss of safety function exists, the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists are required to be entered. This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONs of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level), the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the support system. The ACTIONs for a support system Limiting Condition for Operation adequately address the inoperabilities of that system without reliance on entering its supported system Limiting Condition for Operation. When the loss of function is the result of multiple support systems, the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the supported system.

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the ACTION requirements for the applicable Limiting Condition for Operation begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period or the variable is outside the specified limits, then the equipment is inoperable and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated

BASES

SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. Additionally, the Inservice Inspection Program conforms to the NRC staff positions identified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austinetic Stainless Steel Piping," as approved in NRC Safety Evaluations dated March 6, 1990 and October 22, 1990, or in accordance with alternate measures approved by the NRC staff.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Code and applicable Addenda. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL CONDITION or other specified condition takes precedence over the ASME Code provision that allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, which is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Code provision that allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

BASES

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% Δ k/k or R + 0.28% Δ k/k, as appropriate. The 0.38% Δ k/k includes uncertainties and calculation biases. The value of R in units of % Δ k/k is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of core $k_{effective}$ (k_{eff}). Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in

CONTROL RODS (Continued)

the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. ACTION "e" is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

THIS PAGE INTENTIONALLY LEFT BLANK

CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 topical report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this concentration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containng a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 41.2 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion. To ensure that SLCS pump discharge pressure does not exceed the SLCS relief valve setpoint during operation following an anticipated transient without scram (ATWS) event, no more than two pumps shall be aligned for automatic operation in OPERATIONAL CONDITIONS 1, 2, and 3. This maintains the equivalent control capacity to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS). With three pumps aligned for automatic operation, the system is inoperable and ACTION statement (b) applies.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62. As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 256 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 256 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

---

1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel."

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

PAGE INTENTIONALLY LEFT BLANK

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Reference 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10 CFR 50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as showm in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design anaylsis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

3/4.2.2 (DELETED)

INFORMATION CONTAINED ON

THIS PAGE HAS BEEN

DELETED

LEFT INTENTIONALLY BLANK

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that less than 0.1% of fuel rods in the core are susceptible to transition boiling or that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-2 that are input to a BWR system dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined by the codes used to evaluate transients as described in Reference 2. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 30% RTP.

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits.

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, 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 indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial start-up testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.

2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).

3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 1," NEDO-31401, February 1987 (as amended).

4. Deleted

5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 1 Cycle 1, NEDC-31323, October 1986 including Errata and Addenda Sheet No. 1 dated November 6, 1986.

6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.

7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors, "October 1978.

9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

PAGE INTENTIONALLY LEFT BLANK

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to 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 surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at ≥ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both tip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (includi readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

INTENTIONALLY LEFT BLANK

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded, and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 2, requires two OPERABLE channels of Reactor Vessel Water Level monitoring from each of two overlapping instrumentation loops to ensure monitoring of Reactor Vessel Water Level over the range of -350 inches to +60 inches. Each channel is comprised of one OPERABLE Wide Range Level instrument loop (-150 inches to +60 inches) and one OPERABLE Fuel Zone Range instrument loop (-350 inches to -100 inches). Both instrument loops, Wide Range and Fuel Zone Range, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (Wide Range and Fuel Zone Range) is not maintained.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION (continued)

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 13, requires two OPERABLE channels of Neutron Flux monitoring from each of three overlapping instrumentation loops to ensure monitoring of Neutron Flux over the range of 10^{-6}% to 100% full power. Each channel is comprised of one OPERABLE SRM (10^{-9}% to 10^{-3}% power), one OPERABLE IRM (10^{-4}% to 40% power) and one OPERABLE APRM (0% to 125% power). All three instrument loops, SRM, IRM and APRM, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (SRM, IRM, and APRM) is not maintained.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 CHLORINE AND TOXIC GAS DETECTION SYSTEMS

The OPERABILITY of the chlorine and toxic gas detection systems ensures that an accidental chlorine and/or toxic gas release will be detected promptly and the necessary protective actions will be automatically initiated for chlorine and manually initiated for toxic gas to provide protection for control room personnel. Upon detection of a high concentration of chlorine, the control room emergency ventilation system will automatically be placed in the chlorine isolation mode of operation to provide the required protection. Upon detection of a high concentration of toxic gas, the control room emergency ventilation system will manually be placed in the chlorine isolation mode of operation to provide the required protection. The detection systems required by this specification are consistent with the recommendations of Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release," February 1975.

There are three toxic gas detection subsystems. The high toxic chemical concentration alarm in the Main Control Room annunciates when two of the three subsystems detect a high toxic gas concentration. An Operate/Inop keylock switch is provided for each subsystem which allows an individual subsystem to be placed in the tripped condition. Placing the keylock switch in the INOP position initiates one of the two inputs required to initiate the alarm in the Main Control Room.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 OFFGAS MONITORING INSTRUMENTATION

This instrumentation includes provisions for monitoring the concentrations of potentially explosive gas mixtures and noble gases in the off-gas system.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

REFERENCES:

1. NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

4. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

5. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

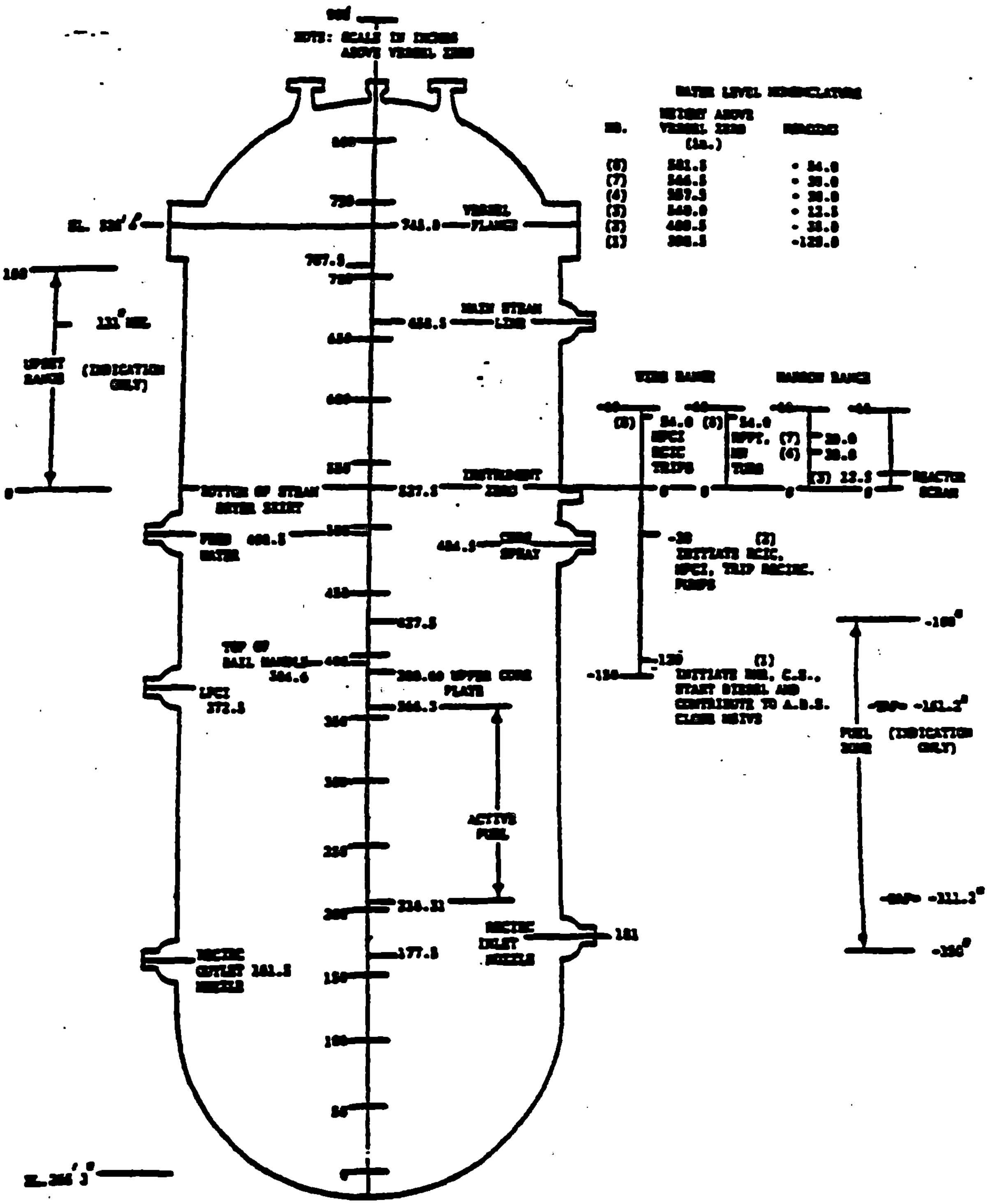
7. Letter, L. A. England (BWROG) to M. J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994.

8. GE Service Information Letter No. 516, "Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants," July 26, 1990.

9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), "Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2," May 02, 2001.

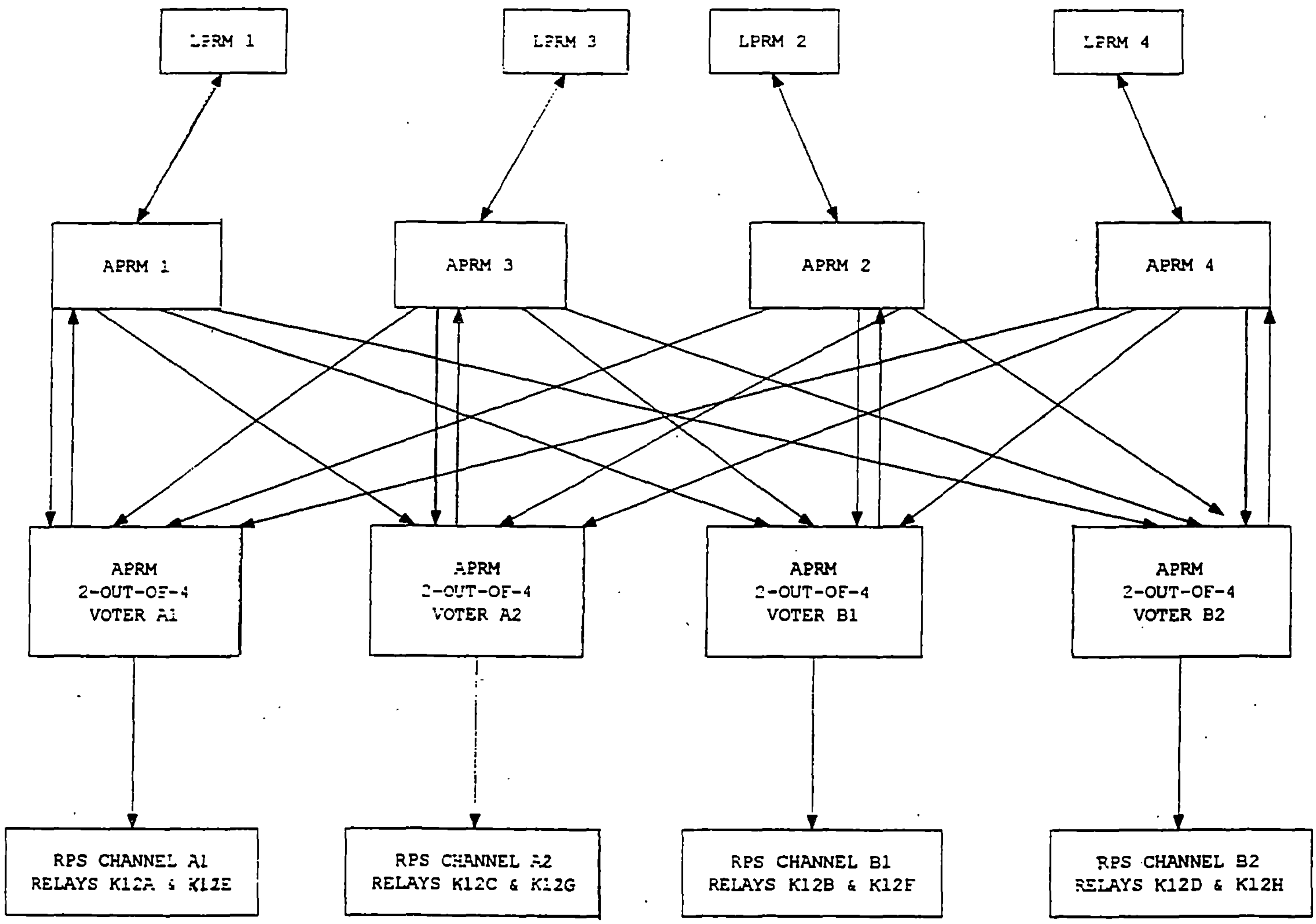
Wide Range Level

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.



BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL



BASES FIGURE B 3/4.3-2

APRM CONFIGURATION

APR 12 2000

(INTENTIONALLY LEFT BLANK)

3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR fuel cladding safety limit is increased as noted by Specification 2.1.2, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internals vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

Systems for quantifying the leakage are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell sump flow monitoring equipment with the required RCS leakage detection instrumentation (i.e., the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump), drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell is the drywell sump monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

An alternate to the drywell floor drain sump flow monitoring system for quantifying UNIDENTIFIED LEAKAGE is the drywell equipment drain sump monitoring system, if the drywell floor drain sump is overflowing to the drywell equipment drain sump. In this configuration, the drywell equipment drain sump collects all leakage into the drywell equipment drain sump and the overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify UNIDENTIFIED LEAKAGE. In this condition, all leakage measured by the drywell equipment drain sump monitoring system is assumed to be UNIDENTIFIED LEAKAGE. The leakage determination process, including the transition to and use of the alternate method is described in station procedures. The alternate method would only be used when the drywell floor drain sump flow monitoring system is unavailable.

In addition to the drywell sump monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the “drywell floor drain flow totalizer”, is not credited for drywell floor drain sump flow monitoring system operability.

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room.

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 4).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 5).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 6 and 7).

A control room alarm allows the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 7). Therefore, these actions provide adequate responses before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of UNIDENTIFIED LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation.

The LCO requires four instruments to be OPERABLE.

The required instrumentation to quantify UNIDENTIFIED LEAKAGE from the RCS consists of either the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump. For either system to be considered operable, the flow monitoring portion of the system must be operable. The identification of an increase in UNIDENTIFIED LEAKAGE will be delayed by the time required for the UNIDENTIFIED LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in UNIDENTIFIED LEAKAGE, depending on the origin and magnitude of the leakage. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the primary containment, can be detected by the gaseous primary containment atmospheric radioactivity monitor. A radioactivity detection system is included for monitoring gaseous activities because of its sensitivity and rapid response to RCS leakage, but it has recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous primary

LIMITING CONDITION FOR OPERATION (LCO) (Continued)

containment atmospheric radioactivity monitor to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous primary containment atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in UNIDENTIFIED LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 9).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system in combination with a gaseous primary containment atmospheric radioactivity monitor, a primary containment air cooler condensate flow rate monitoring system, and a primary containment pressure and temperature monitoring system provides an acceptable minimum.

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

   The 12 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

B. With required drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

   With required drywell sump monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref. SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment of more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state

ACTIONS (Continued)

that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. With the drywell floor drain sump monitoring system inoperable and the drywell unit coolers condensate flow rate monitoring system inoperable, one of the two remaining means of detecting leakage is the primary containment atmospheric gaseous radiation monitor. The primary containment atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the primary containment atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of UNIDENTIFIED LEAKAGE. The administrative methods are the drywell cooling fan inlet/outlet temperatures, drywell equipment drain sump temperature indicator, drywell equipment drain tank hi temperature indicator, and drywell equipment drain tank flow indicator. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

In addition to the primary containment atmospheric gaseous radiation monitor and indirect methods of monitoring RCS leakage, the primary containment pressure and temperature monitoring system is also available to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

ACTIONS (Continued)

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

G. If any required ACTION of Conditions A, B, C, D, E or F cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a
This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string.

SR 4.4.3.1.c
The SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3.
4. LGS UFSAR, Section 5.2.5.2.1.4.
5. LGS UFSAR, Section 5.2.5.2.1.1(2).
6. GEAP-5620, April 1968
7. NUREG-75/067, October 1975.
8. LGS UFSAR, Section 5.2.5.6.
9. LGS UFSAR, Section 5.2.5.2.1.5

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in the Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in the THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

INTENTIONALLY LEFT BLANK

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves of Figure 3.4.6.1-1 are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are shown in Table B 3/4.4.6-1. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using Bases Figure B 3/4.4.6-1 and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curves, Figure 3.4.6.1-1, include a shift in RT_{NDT} for conditions at 32 EFPY. The A, B and C limit curves are predicted to be bounding for all areas of the RPV until 32 EFPY. In addition, an intermediate A curve was previously provided for 22 EFPY. However, Unit 1 exceeded 22 EFPY during Cycle 14. Therefore, the A22 curve identified in Tech. Spec. Figure 3.4.6.1-1 (Pressure/Temperature Curves) can no longer be used when performing the Reactor Vessel Pressure Test for Unit 1.

The pressure-temperature limit lines shown in Figures 3.4.6.1-1, curves C, and A, for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 (DELETED)

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exhanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, and the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is

3/4.4.9 RESIDUAL HEAT REMOVAL (Continued)

required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to initially placing the system in operation during reactor shutdown. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System whose use is typically preceded by system piping flushes that disturb both the RHR pump suction and discharge piping. RHR Shutdown Cooling System is flushed and manually aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. In the event that RHR Shutdown Cooling is required for emergency service, the system operating procedures that align and start the RHR System in shutdown cooling mode include the flexibility to eliminate piping flushes while maintaining minimum requirements to ensure that the suction and discharge flow paths are sufficiently filled with water. The RHR Shutdown Cooling System surveillance is met through the performance of the operating procedures that initially place the RHR shutdown cooling sub-system in service.

This surveillance requirement is modified by a Note allowing sufficient time (12 hours) to align the RHR System for Shutdown Cooling operation after reactor dome pressure is less than the RHR cut-in permissive set point.

BASES TABLE B 3/4.4.6-1
REACTOR VESSEL TOUGHNESS*

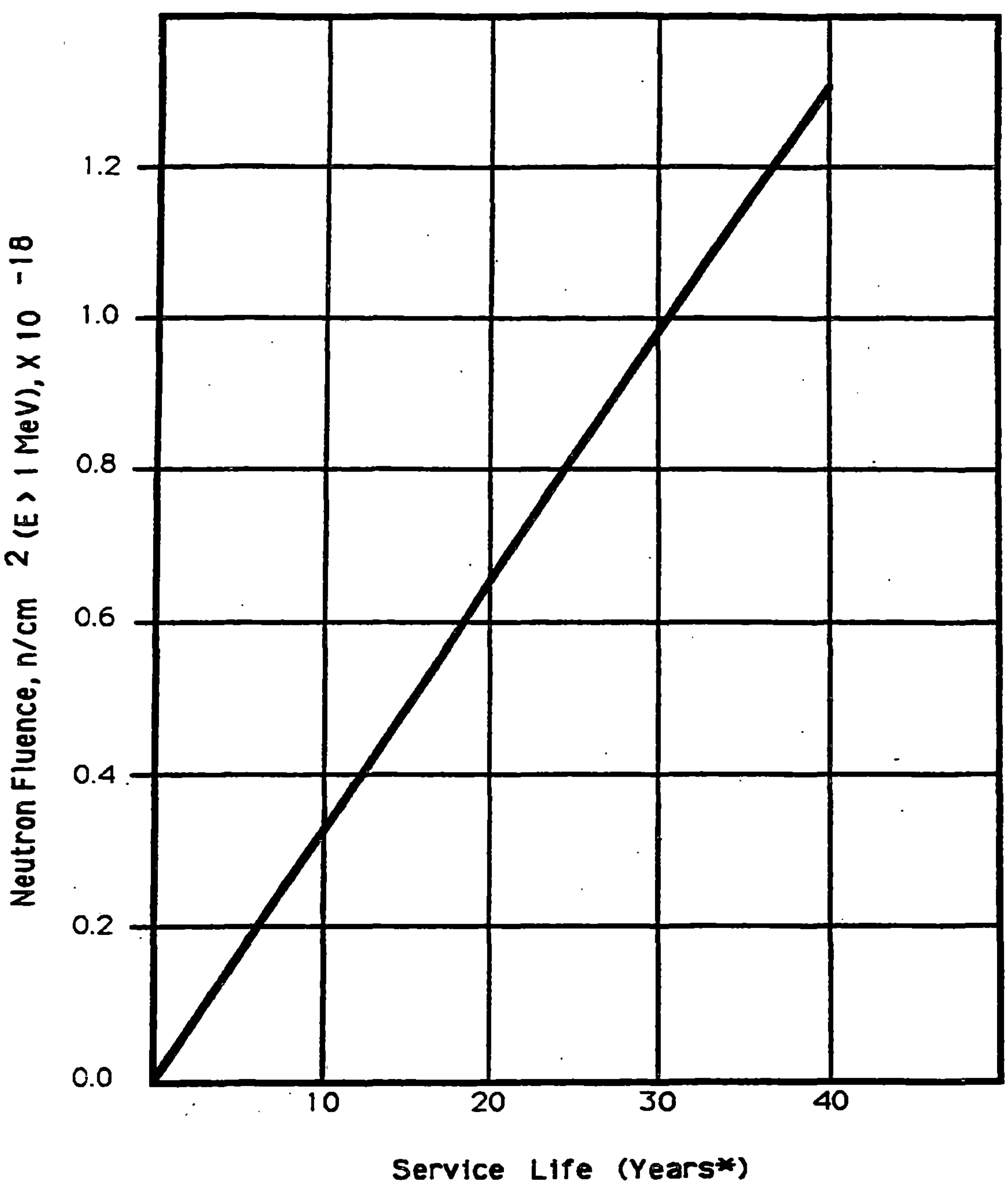
BELTLINE COMPONENT	WELD SEAM I.D. OR MAT'L TYPE	HEAT/SLAB OR HEAT/LOT	CU (%)	Ni (%)	STARTING RT_{NDT} (°F)	ΔRT_{NDT} **(°F)	MIN. UPPER SHELF (LFT-LBS)	ART (°F)
Plate	SA-533 Gr. B, CL. 1	C 7677-1	.11	.5	+20	+35	NA	+89
Weld	AB (Field Weld)	640892/ J424B27AE	.09	1.0	-60	+58	NA	+54

NOTES: * Based on 110% of original rated power.
** These values are given only for the benefit of calculating the end-of-life (EOL/32 EFPY) RT_{NDT}

NON-BELTLINE COMPONENT	MT'L TYPE OR WELD SEAM I.D.	HEAT/SLAB OR HEAT/LOT	HIGHEST STARTING RT_{NDT} (°F)
Shell Ring	SA 533, Gr. B, CL. 1	C7711-1	+20
Bottom Head Dome	"	C7973-1	+12
Bottom Head Torus	"	C7973-1	+12
Top Head Dome	"	A6834-1	+10
Top Head Torus	"	B1993-1	+10
Top Head Flange	SA-508, CL. 2	123B195-289	+10
Vessel Flange	"	2V1924-302	-20
Feedwater Nozzle	"	Q2Q22W-412	-20
Weld	Non-Beltline	All	-12
LPCI Nozzle***	SA-508, CL. 2	Q2Q25W	-6
Closure Studs	SA-540, Gr. B-24	All	Meet requirements of 45 ft-lbs and 25 mils Lat. Exp. at +10°F

Note: *** The design of the LPCI nozzles results in their experiencing an EOL fluence in excess of 10^{17} N/Cm^2 which predicts an EOL (32 EFPY) RT_{NDT} of +41°F.

SEP 15 2000



BASES FIGURE B 3/4.4.6-1

FAST NEUTRON FLUENCE (E>1 MeV) AT 1/4 T AS A FUNCTION OF SERVICE LIFE*

---

* At 90% of Rated Thermal Power and 90% availability

3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

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

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

ECCS - OPERATING and SHUTDOWN (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. ECCS injection/spray

ECCS - OPERATING and SHUTDOWN (Continued)

subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS sub-system out-of-service time allowances.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

ECCS - OPERATING and SHUTDOWN (Continued)

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

Repair work might require making the suppression chamber inoperable. This specification will permit those repairs to be made and at the same time give assurance that the irradiated fuel has an adequate cooling water supply when the suppression chamber must be made inoperable, including draining, in OPERATIONAL CONDITION 4 or 5.

In OPERATIONAL CONDITION 4 and 5 the suppression chamber minimum required water volume is reduced because the reactor coolant is maintained at or below 200°F. Since pressure suppression is not required below 212°F, the minimum water volume is based on NPSH, recirculation volume and vortex prevention plus a safety margin for conservatism.

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses at the design basis LOCA maximum peak containment pressure of 44 psig, Pa. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to ≤ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure. Management of gas voids is important to Suppression Pool Cooling/Spray Subsystem OPERABILITY.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft^3 results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft^3 results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

RHR Suppression Pool Cooling/Spray subsystem piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR suppression pool subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR Suppression Pool Cooling/Spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate ^{3}10,000 gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger, and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. 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.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

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 safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety/relief valve to assure mixing and uniformity of energy insertion to the pool.

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of $A/\sqrt{k}$ equal to 0.0500 ft^2 to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft^2 ensures that the design basis for the steam bypass analysis is met.

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05\ ft^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel or during CORE ALTERATIONS and alignment of the Standby Gas Treatment System to the refueling area is not required. The control room dose analysis for the Fuel Handling Accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the Standby Gas Treatment System to be aligned to the refueling area.

However, when handling RECENTLY IRRADIATED FUEL or during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel, secondary containment integrity of the refueling area is required and alignment of the Standby Gas Treatment System to the refueling area is required. The AST fuel handling analysis does not include an accident involving RECENTLY IRRADIATED FUEL or an accident involving draining the reactor vessel.

The Standby Gas Treatment System is required to be OPERABLE when handling irradiated fuel, handling RECENTLY IRRADIATED FUEL, during CORE ALTERATIONS and during operations with a potential to drain the vessel with the vessel head removed and fuel in the vessel. Fuel Handling Accident releases from the North Stack must be filtered through the Standby Gas Treatment System to maintain control room doses within regulatory limits. The OPERABILITY of the Standby Gas Treatment System assures that releases, if made through the North Stack, are filtered prior to release.

SECONDARY CONTAINMENT (Continued)

Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 require verifying that one secondary containment personnel access door in each access opening is closed which provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer personnel access door closed. Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 provide an allowance for brief, inadvertent, simultaneous openings of redundant secondary containment personnel access doors for normal entry and exit conditions.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

3/4.6.5 SECONDARY CONTAINMENT (Continued)

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of 5764 ± 10% cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHR and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, The CREFAS System provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4

2. UFSAR Section 9.5

3. Regulatory Guide 1.196

4. NEI 99-03, "Control Room Habitability Assessment Guidance, "June 2001.

5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RCIC System and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.7.3.a.2 is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

3/4.7.4 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 nonsafety-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.

Snubbers are classified and grouped by design and manufacturer but not by size. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip, and 100-kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purposes of this Technical Specification would be of a different type, as would hydraulic snubbers from either manufacturer.

A list of individual snubbers with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each snubber shall be determined and approved by the Plant Operations Review Committee. The determination shall be based upon the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.), and the recommendations of Regulatory Guides 8.8 and 8.10. The addition or deletion of any snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection schedule is based on the number of unacceptable snubbers found during the previous inspection in proportion to the sizes of the various snubber populations or categories. The visual inspection interval is based on a fuel cycle of up to 24 months and may be as long as two fuel cycles or 48 months depending on the number of unacceptable snubbers found during the previous visual inspection. The visual inspection schedule provides confidence that a constant level of snubber protection is being maintained and generally allows performance of visual inspections and corrective actions during plant outages. 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 required a shorter inspection interval will override the previous schedule.

A snubber is considered inoperable if it fails the acceptance criteria of the visual inspection.

SNUBBERS (Continued)

To provide assurance of snubber functional reliability one of two functional testing methods is used with the stated acceptance criteria:

1. Functionally test 13.3% sample of a type of snubber with an additional 1/2 sample tested for each functional testing failure, or

2. Functionally test 37 snubbers and determine sample acceptance using Figure 4.7.4-1.

Functional Testing sample plans are based on ASME/ANSI OMc-1990 Addenda to ASME/ANSI OM-1987, Part 4.

Figure 4.7.4-1 was developed using "Wald's Sequential Probability Ratio Plan" as described in Quality Control and Industrial Statistics" by Acheson J. Duncan.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (i.e., newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life.

3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e,, sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4 7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

DEC 2 0 1995

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformers 8A/8B) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 8A/8B transformers. Additionally, the Unit Auxiliary Buses do not transfer to the 8A/8B transformers; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Onsite A.C. operability requirements for common systems such as RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components, and devices, that depend on the remaining OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action i, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, "Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation," dated September 27, 1993.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as ≤ 2 amps, and for Divisions 3 and 4 as ≤ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits(i.e., greater than minimum level indication mark), the bOttery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108,

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

"Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE Standard 450-1995.

This Surveillance Requirement (4.8.2.1.a.1) states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained, the Actions of 3.8.2.1 Action a., provides the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

THIS PAGE INTENTIONALLY LEFT BLANK

AUG 2 1 2000

ECR 00-00937

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core unloading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

Inadvertent criticality is prevented by the refueling interlocks that block unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn or withdrawal of a rod from the core while the grapple is over the core and loaded with fuel). The hoist loaded values identified in Sections 4.9.6.1b and 4.9.6.1c support the refueling interlock logic by ensuring that the hoist fuel loaded switches function with a load lighter than the weight of a single fuel assembly in water. Load values represent fuel (load) on the grapple. The values of 485 +/- 50 pounds and 550 + 0, -115 pounds are both less than the weight of a single fuel assembly in water attached to the grapple. These load values ensure that as soon as a fuel assembly is grappled and lifted, the refueling interlocks (control rod block and bridge motion interlock) are enforced as required. The hoist load weighing system is compensated for mast weight to ensure that lifting of components other than fuel assemblies (e.g., blade guides) do not cause inadvertent control rod blocks or bridge motion stops.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication. Management of gas voids is important to RHR Shutdown Cooling Subsystem OPERABILITY. |

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION (Continued)

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensible gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to placing the system in operation when in OPCON 5. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System that is aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. An RHR Shutdown Cooling sub-system that is already in operation at the time of entry into the APPLICABILITY is OPERABLE. For an idle RHR Shutdown Cooling subsystem, the surveillance is met through the performance of the operating procedures that place the RHR Shutdown Cooling subsystem in service.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

3.4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 RESERVED - CURRENTLY NOT USED

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F and less than or equal to 212°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 1 and 3. Operations with the Potential for Draining the Vessel, Core alterations, and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.2.2 through 3/4.11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.2.5 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the main condenser offgas treatment system is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen below its flammability limit provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4 11.2.7, 3/4 11.3, and 3/4 11.4 (Deleted) - INFORMATION FROM THESE SECTIONS RELOCATED TO THE ODCM OR PCP.

PAGE INTENTIONALLY LEFT BLANK

Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS SECTION HAS BEEN RELOCATED TO THE ODCM. BASES PAGE B 3/4 12-2 HAS BEEN INTENTIONALLY OMITTED.

PAGE INTENTIONALLY LEFT BLANK

License No. NPF-85

Limerick Generating Station, Unit No. 2

Docket No. 50-353

Issued by the
U.S. Nuclear Regulatory
Commission

Office of Nuclear Reactor Regulation

BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

BASES

Specifications 3.0.1 through 3.0.4 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

> "Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. It is not intended that the shutdown ACTION requirement be used as an operation convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routine) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in COLD SHUTDOWN when a shutdown is required during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is required, the time limit for reaching the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if STARTUP is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower CONDITION of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered permit continued operation in the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time. Compliance with ACTION requirements that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made in accordance with the provisions of the ACTION requirements.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk

management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this

context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONs. The sole purpose of this Specification is to provide an exception to Specifications 3.0.1 and 3.0.2 (e.g., to not comply with the applicable ACTION(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service, or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONs is limited to the time necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with required ACTIONs and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

Specification 3.0.6 establishes an exception to Specifications 3.0.1 and 3.0.2 for supported systems that have a support system Limiting Condition for Operation specified in the Technical Specifications (TS). The exception to Specification 3.0.1 is provided because Specification 3.0.1 would require that the ACTIONs of the associated inoperable supported system Limiting Condition for Operation be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system Limiting Condition for Operation's ACTIONs. These ACTIONs may include entering the supported system's ACTIONs or may specify other ACTIONs. The exception to Specification 3.0.2 is provided because Specification 3.0.2 would consider not entering into the ACTIONs for the supported system within the specified time intervals as a TS noncompliance.

When a support system is inoperable and there is a Limiting Condition for Operation specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' ACTIONs unless directed to do so by the support system's ACTIONs. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Limiting Condition for Operations' ACTIONs are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's ACTIONs.

However, there are instances where a support system's ACTION may either direct a supported system to be declared inoperable or direct entry into ACTIONS for the supported system. This may occur immediately or after some specified delay to perform some other ACTION. Regardless of whether it is immediate or after some delay, when a support system's ACTION directs a supported system to be declared inoperable or directs entry into ACTIONs for a supported system, the applicable ACTIONs shall be entered in accordance with Specification 3.0.1.

Specification 6.17, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into Specification 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system ACTIONs. The SFDP implements the requirements of Specification 3.0.6.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

EXAMPLE B 3.0.6-1
If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

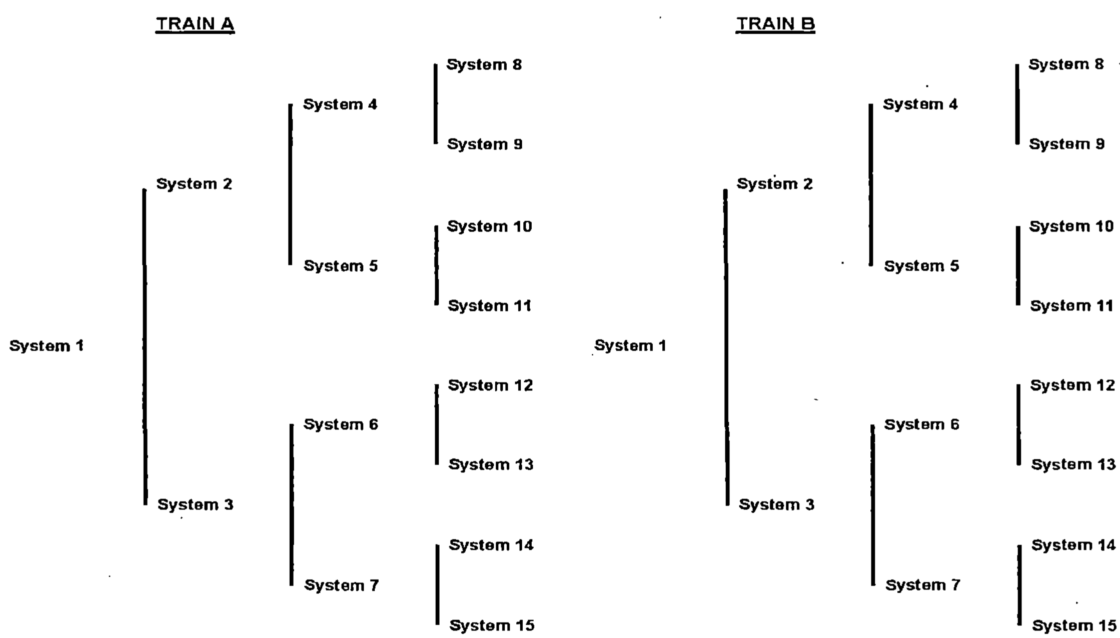


Figure B 3.0-1
Configuration of Trains and Systems

If an evaluation determines that a loss of safety function exists, the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists are required to be entered. This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONs of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level), the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the support system. The ACTIONs for a support system Limiting Condition for Operation adequately address the inoperabilities of that system without reliance on entering its supported system Limiting Condition for Operation. When the loss of function is the result of multiple support systems, the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the supported system.

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the ACTION requirements for the applicable Limiting Condition for Operation begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period or the variable is outside the specified limits, then the equipment is inoperable and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified

condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. Additionally, the Inservice Inspection Program conforms to the NRC staff positions identified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austinetic Stainless Steel Piping," as approved in NRC Safety Evaluations dated March 6, 1990 and October 22, 1990, or in accordance with alternate measures approved by the NRC staff.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Code and applicable Addenda. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL CONDITION or other specified condition takes precedence over the ASME Code provision that allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, which is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Code provision that allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

BASES

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% Δ k/k or R + 0.28% Δ k/k, as appropriate. The 0.38% Δ k/k includes uncertainties and calculation biases. The value of R in units of % Δ k/k is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of core $k_{effective}$ (k_{eff}). Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single

CONTROL RODS (Continued)

failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. ACTION "e" is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 Topical Report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this concentration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containng a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 41.2 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion. To ensure that SLCS pump discharge pressure does not exceed the SLCS relief valve setpoint during operation following an anticipated transient without scram (ATWS) event, no more than two pumps shall be aligned for automatic operation in OPERATIONAL CONDITIONS 1, 2, and 3. This maintains the equivalent control capacity to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS). With three pumps aligned for automatic operation, the system is inoperable and ACTION statement (b) applies.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62. As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 256 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 256 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

---

1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel".

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Reference 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10CFR50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as showm in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design anaylsis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

JAN 3 1 1995

3/4.2.2 (DELETED)

INFORMATION CONTAINED ON

THIS PAGE HAS BEEN

DELETED

LEFT INTENTIONALLY BLANK

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that less than 0.1% of fuel rods in the core are susceptible to transition boiling or that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-2 that are input to a BWR system dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined by the codes used to evaluate transients as described in Reference 2. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 30% RTP.

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits.

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, 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 indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial startup testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.

2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).

3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 2," NEDC-31930P (as amended).

4. Deleted

5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 2 Cycle 1, NEDC-31578P, March 1989 including Errata and Addenda Sheet No. 1 dated May 31, 1989.

6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.

7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to 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 surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at ≥ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow /

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Progam and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO-32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded, and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A. The Unit 1 RHR transfer switches are included only due to their potential impact on the RHRSW system, which is common to both units.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 2, requires two OPERABLE channels of Reactor Vessel Water Level monitoring from each of two overlapping instrumentation loops to ensure monitoring of Reactor Vessel Water Level over the range of -350 inches to +60 inches. Each channel is comprised of one OPERABLE Wide Range Level instrument loop (-150 inches to +60 inches) and one OPERABLE Fuel Zone Range instrument loop (-350 inches to -100 inches). Both instrument loops, Wide Range and Fuel Zone Range, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (Wide Range and Fuel Zone Range) is not maintained.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION (continued)

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 13, requires two OPERABLE channels of Neutron Flux monitoring from each of three overlapping instrumentation loops to ensure monitoring of Neutron Flux over the range of 10^{-6}% to 100% full power. Each channel is comprised of one OPERABLE SRM (10^{-9}% to 10^{-3}% power), one OPERABLE IRM (10^{-4}% to 40% power) and one OPERABLE APRM (0% to 125% power). All three instrument loops, SRM, IRM and APRM, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (SRM, IRM, and APRM) is not maintained.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 CHLORINE AND TOXIC GAS DETECTION SYSTEMS

The OPERABILITY of the chlorine and toxic gas detection systems ensures that an accidental chlorine and/or toxic gas release will be detected promptly and the necessary protective actions will be automatically initiated for chlorine and manually initiated for toxic gas to provide protection for control room personnel. Upon detection of a high concentration of chlorine, the control room emergency ventilation system will automatically be placed in the chlorine isolation mode of operation to provide the required protection. Upon detection of a high concentration of toxic gas, the control room emergency ventilation system will manually be placed in the chlorine isolation mode of operation to provide the required protection. The detection systems required by this specification are consistent with the recommendations of Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release," February 1975.

There are three toxic gas detection subsystems. The high toxic chemical concentration alarm in the Main Control Room annunciates when two of the three subsystems detect a high toxic gas concentration. An Operate/Inop keylock switch is provided for each subsystem which allows an individual subsystem to be placed in the tripped condition. Placing the keylock switch in the INOP position initiates one of the two inputs required to initiate the alarm in the Main Control Room.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 OFFGAS MONITORING INSTRUMENTATION

This instrumentation includes provisions for monitoring the concentrations of potentially explosive gas mixtures and noble gases in the off-gas system.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

REFERENCES:

1. NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

4. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

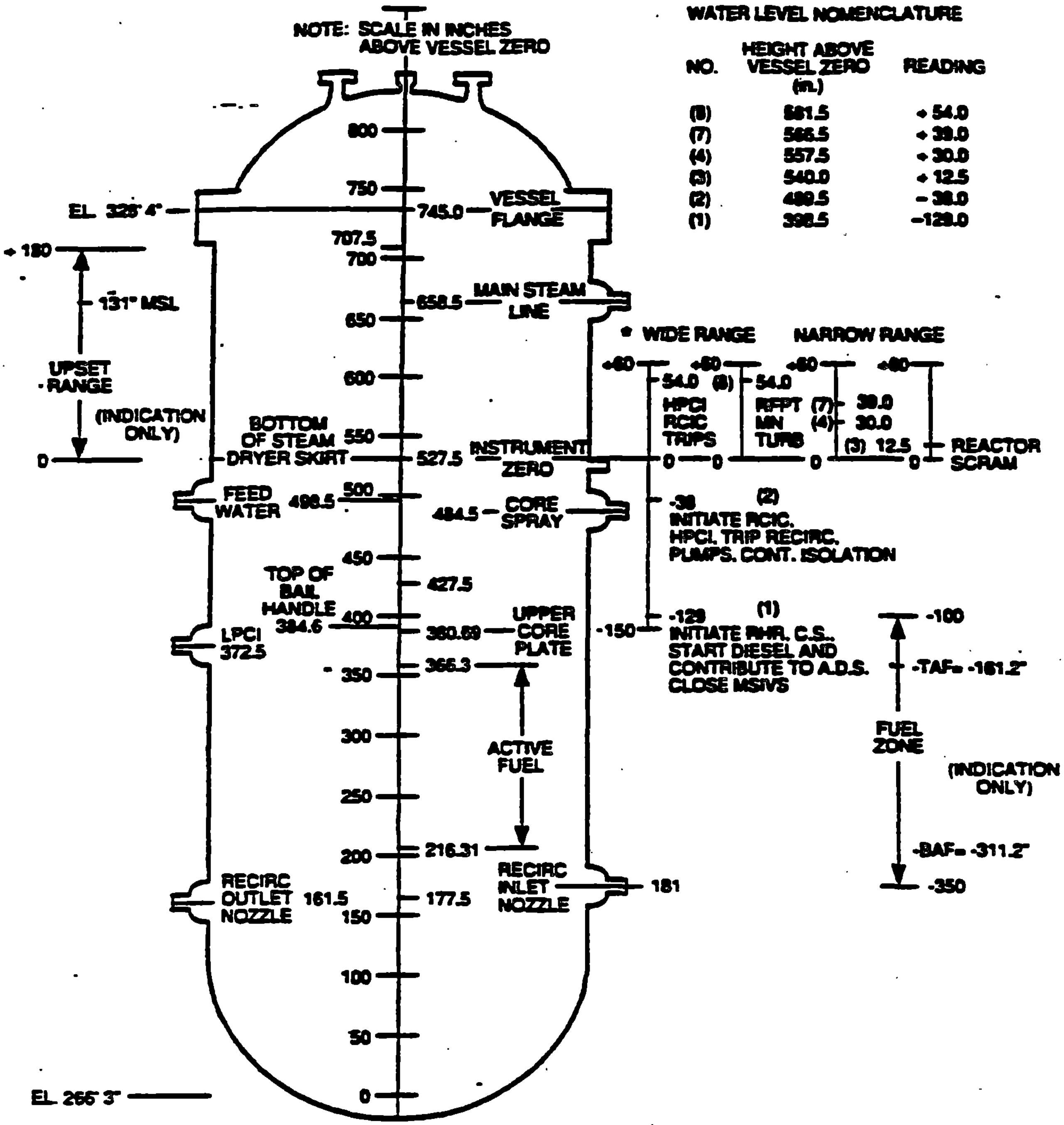
5. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

7. Letter, L. A. England (BWROG) to M. J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994.

8. GE Service Information Letter No. 516, "Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants," July 26, 1990.

9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), "Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2," May 02, 2001.

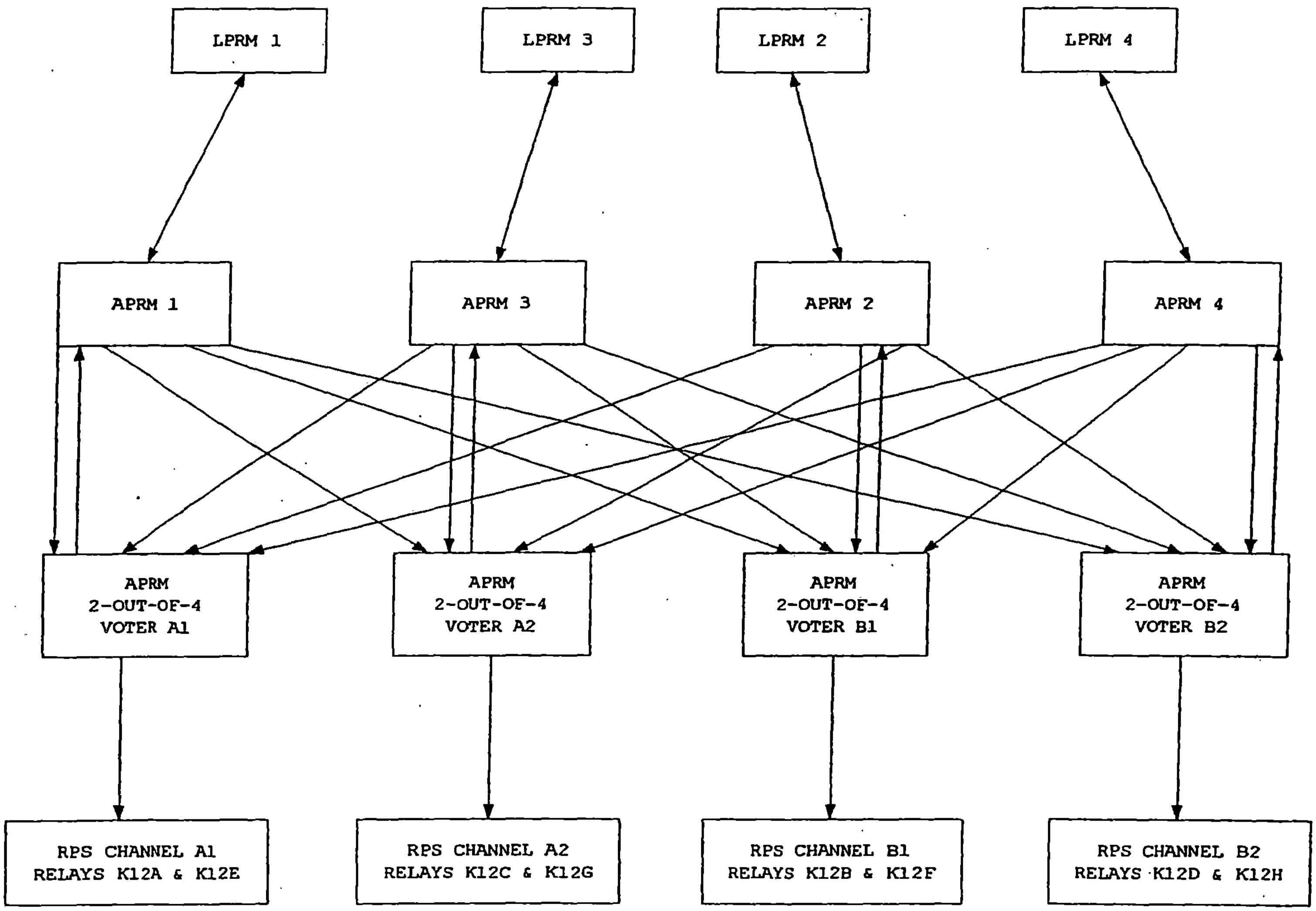


* Wide Range Level

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.

BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL



BASES FIGURE B 3/4.3-2

APRM CONFIGURATION

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR fuel cladding safety limit is increased as noted by Specification 2.1.2, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internals vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

Systems for quantifying the leakage are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell sump flow monitoring equipment with the required RCS leakage detection instrumentation (i.e., the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump), drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell is the drywell sump monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

An alternate to the drywell floor drain sump flow monitoring system for quantifying UNIDENTIFIED LEAKAGE is the drywell equipment drain sump monitoring system, if the drywell floor drain sump is overflowing to the drywell equipment drain sump. In this configuration, the drywell equipment drain sump collects all leakage into the drywell equipment drain sump and the overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify UNIDENTIFIED LEAKAGE. In this condition, all leakage measured by the drywell equipment drain sump monitoring system is assumed to be UNIDENTIFIED LEAKAGE. The leakage determination process, including the transition to and use of the alternate method is described in station procedures. The alternate method would only be used when the drywell floor drain sump flow monitoring system is unavailable.

In addition to the drywell sump monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the "drywell floor drain flow totalizer", is not credited for drywell floor drain sump flow monitoring system operability.

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room.

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 4).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 5).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 6 and 7).

A control room alarm allow the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 7). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of UNIDENTIFIED LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation.

The LCO requires four instruments to be OPERABLE.

The required instrumentation to quantify UNIDENTIFIED LEAKAGE from the RCS consists of either the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump. For either system to be considered operable, the flow monitoring portion of the system must be operable. The identification of an increase in UNIDENTIFIED LEAKAGE will be delayed by the time required for the UNIDENTIFIED LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in UNIDENTIFIED LEAKAGE, depending on the origin and magnitude of the leakage. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the primary containment, can be detected by the gaseous primary containment atmospheric radioactivity monitor. A radioactivity detection system is included for monitoring gaseous activities because of its sensitivity and rapid response to RCS leakage, but it has recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous primary

LIMITING CONDITION FOR OPERATION (LCO) (Continued)

containment atmospheric radioactivity monitor to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous primary containment atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in UNIDENTIFIED LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 9).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system in combination with a gaseous primary containment atmospheric radioactivity monitor, a primary containment air cooler condensate flow rate monitoring system, and a primary containment pressure and temperature monitoring system provides an acceptable minimum.

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

   The 12 hours interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

B. With required drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

   With required drywell sump monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref: SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain sump monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment at a more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state

ACTIONS (Continued)

that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. With the drywell floor drain sump monitoring system inoperable and the drywell unit coolers condensate flow rate monitoring system inoperable, one of the two remaining means of detecting leakage is the primary containment atmospheric gaseous radiation monitor. The primary containment atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the primary containment atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of UNIDENTIFIED LEAKAGE. The administrative methods are the drywell cooling fan inlet/outlet temperatures, drywell equipment drain sump temperature indicator, drywell equipment drain tank hi temperature indicator, and drywell equipment drain tank flow indicator. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

In addition to the primary containment atmospheric gaseous radiation monitor and indirect methods of monitoring RCS leakage, the primary containment pressure and temperature monitoring system is also available to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

ACTIONS (Continued)

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

G. If any required ACTION of Conditions A, B, C, D, E or F cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a
This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string.

SR 4.4.3.1.c
This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3
4. LGS UFSAR, Section 5.2.5.2.1.4
5. LGS UFSAR, Section 5.2.5.2.1.1(2)
6. GEAP-5620, April 1968.
7. NUREG-75/067, October 1975.
8. LGS UFSAR, Section 5.2.5.6.
9. LGS UFSAR, Section 5.2.5.2.1.5

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in The Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2-hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves of Figure 3.4.6.1-1 are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are shown in Table B 3/4.4.6-1. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using Bases Figure B 3/4.4.6-1 and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curve, Figure 3.4.6.1-1, curves A, B and C, includes an assumed shift in RT_{NDT} for the conditions at 32 EFPY. In addition, an intermediate A curve was previously provided for 22 EFPY. However, the accumulated EFPY for Unit 2 will exceed 22 EFPY during Cycle 13 for Unit 2. Therefore, the A22 curve identified in Tech. Spec. Figure 3.4.6.1-1 (Pressure/Temperature Curves) can no longer be used when performing the Reactor Vessel Pressure Test for Unit 2. The A, B and C limit curves are predicted to be bounding for all areas of the RPV until 32 EFPY.

The pressure-temperature limit lines shown in Figures 3.4.6.1-1, curves C, and A, for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 (DELETED)

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exhanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, <u>and</u> the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is

3/4.4.9 RESIDUAL HEAT REMOVAL (Continued)

required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to initially placing the system in operation during reactor shutdown. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System whose use is typically preceded by system piping flushes that disturb both the RHR pump suction and discharge piping. RHR Shutdown Cooling System is flushed and manually aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. In the event that RHR Shutdown Cooling is required for emergency service, the system operating procedures that align and start the RHR System in shutdown cooling mode include the flexibility to eliminate piping flushes while maintaining minimum requirements to ensure that the suction and discharge flow paths are sufficiently filled with water. The RHR Shutdown Cooling System surveillance is met through the performance of the operating procedures that initially place the RHR shutdown cooling sub-system in service.

This surveillance requirement is modified by a Note allowing sufficient time (12 hours) to align the RHR System for Shutdown Cooling operation after reactor dome pressure is less than the RHR cut-in permissive set point.

BASES TABLE B 3/4.4.6-1
REACTOR VESSEL TOUGHNESS*

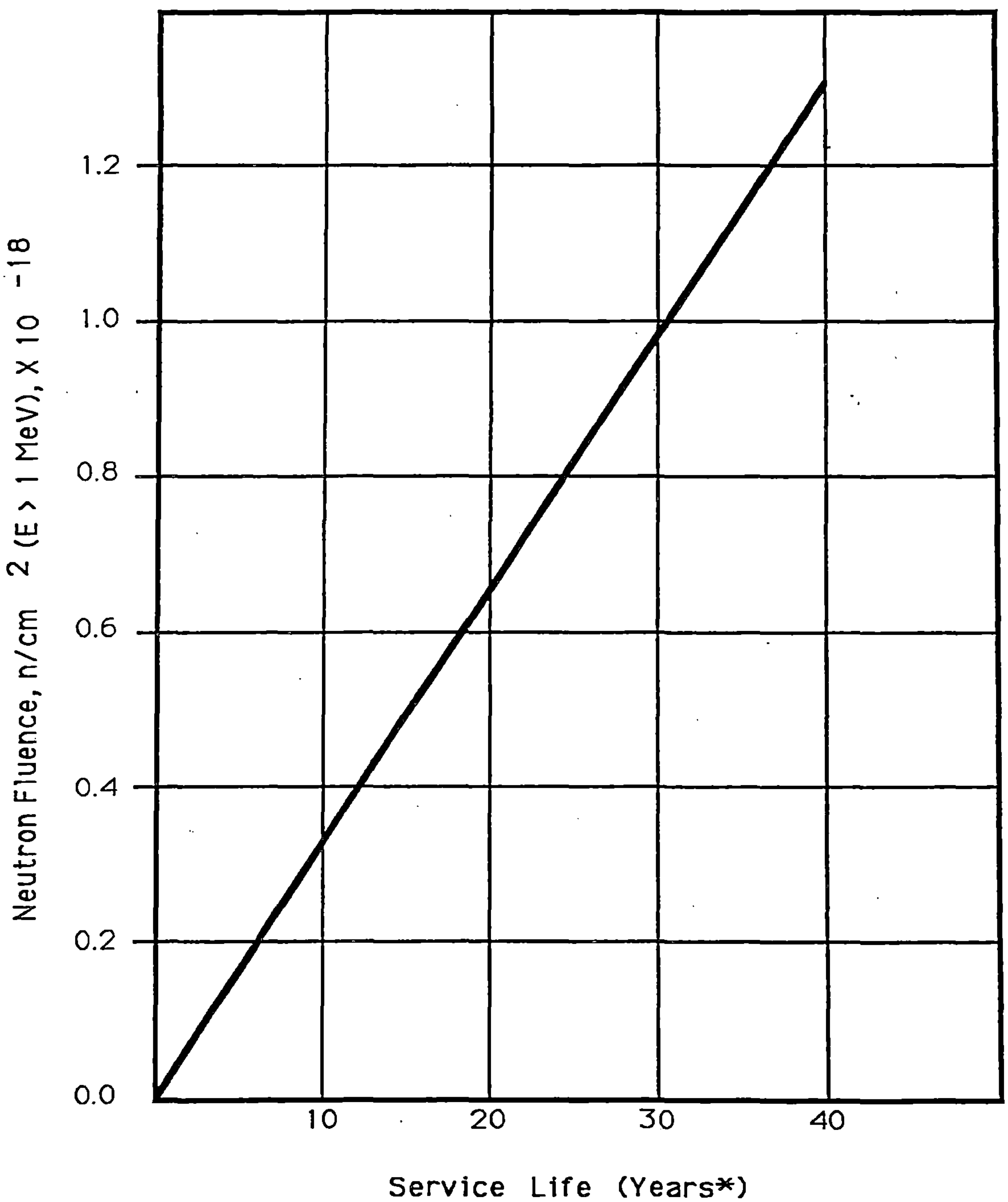
LIMITING BELTLINE COMPONENT	WELD SEAM I.D. OR MAT'L TYPE	HEAT/SLAB OR HEAT/LOT	CU (%)	Ni (%)	STARTING RT_{NDT} (°F)	ΔRT_{NDT} **(°F)	MIN.UPPER SHELF (LFT-LBS)	ART (°F)
Plate	SA-533 Gr. B,CL. 1	B 3416-1	.14	.65	+40	+48	NA	+122
Weld	AB (Field Weld)	640892/ J424B27AE	.09	1.0	-60	+58	NA	+54

NOTES: * Based on 110% of original power.
** These values are given only for the benefit of calculating the end-of-life (EOL/32 EFPY) RT_{NDT}

NON-BELTLINE COMPONENT	MT'L TYPE OR WELD SEAM I.D.	HEAT/SLAB OR HEAT/LOT	HIGHEST STARTING RT_{NDT} (°F)
Top Shell Ring	SA 533, Gr. B, CL. 1	C9800-2	-16
Bottom Head Dome	"	C9245-2	+22
Bottom Head Torus	"	C9362-2	+28
Top Head Torus	"	C9646-2	-20
Top Head Flange	SA-508, CL. 2	123B300	+10
Vessel Flange	"	2L2058	+10
Feedwater Nozzle	"	Q2Q29W	0
Weld	Non-Beltline	All	-12
LPCI Nozzle***	SA-508, CL. 2	Q2Q33W	-4
Closure Studs	SA-540, Gr. B-24	All	Meet requirements of 45 ft-lbs and 25 mils Lat. Exp. at +10°F

*** The design of the LPCI nozzles results in their experiencing an EOL fluence in excess of 10^{17} N/Cm^2 which predicts an EOL (32 EFPY) RT_{NDT} of +35°F.

INTENTIONALLY LEFT BLANK



BASES FIGURE B 3/4.4.6-1

FAST NEUTRON FLUENCE (E>1 MeV) AT 1/4 T AS A FUNCTION OF SERVICE LIFE*

* At 90% of Rated Thermal Power and 90% availability

FEB 1 6 1995

PAGE INTENTIONALLY LEFT BLANK

3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

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

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

ECCS - OPERATING and SHUTDOWN (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS - OPERATING and SHUTDOWN (Continued)

ECCS injection/spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS sub-system out-of-service time allowances.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

ECCS - OPERATING and SHUTDOWN (Continued)

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

Repair work might require making the suppression chamber inoperable. This specification will permit those repairs to be made and at the same time give assurance that the irradiated fuel has an adequate cooling water supply when the suppression chamber must be made inoperable, including draining, in OPERATIONAL CONDITION 4 or 5.

In OPERATIONAL CONDITION 4 and 5 the suppression chamber minimum required water volume is reduced because the reactor coolant is maintained at or below 200°F. Since pressure suppression is not required below 212°F, the minimum water volume is based on NPSH, recirculation volume and vortex prevention plus a safety margin for conservatism.

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses at the design basis LOCA maximum peak containment pressure of 44 psig, Pa. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to $\leq$ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure. Management of gas voids is important to Suppression Pool Cooling/Spray Subsystem OPERABILITY.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft^3 results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft^3 results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

RHR Suppression Pool Cooling/Spray subsystem piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR suppression pool subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR Suppression Pool Cooling/Spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate ^{3}10,000 gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger, and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. 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.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

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 safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety/relief valve to assure mixing and uniformity of energy insertion to the pool.

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of $A/\sqrt{k}$ equal to 0.0500 ft^2 to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft^2 ensures that the design basis for the steam bypass analysis is met

THIS PAGE INTENTIONALLY LEFT BLANK

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel or during CORE ALTERATIONS and alignment of the Standby Gas Treatment System to the refueling area is not required. The control room dose analysis for the Fuel Handling Accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the Standby Gas Treatment System to be aligned to the refueling area.

However, when handling RECENTLY IRRADIATED FUEL or during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel, secondary containment integrity of the refueling area is required and alignment of the Standby Gas Treatment System to the refueling area is required. The AST fuel handling analysis does not include an accident involving RECENTLY IRRADIATED FUEL or an accident involving draining the reactor vessel.

The Standby Gas Treatment System is required to be OPERABLE when handling irradiated fuel, handling RECENTLY IRRADIATED FUEL, during CORE ALTERATIONS and during operations with a potential to drain the vessel with the vessel head removed and fuel in the vessel. Fuel Handling Accident releases from the North Stack must be filtered through the Standby Gas Treatment System to maintain control room doses within regulatory limits. The OPERABILITY of the Standby Gas Treatment System assures that releases, if made through the North Stack, are filtered prior to release.

SECONDARY CONTAINMENT (Continued)

Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 require verifying that one secondary containment personnel access door in each access opening is closed which provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer personnel access door closed. Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 provide an allowance for brief, inadvertent, simultaneous openings of redundant secondary containment personnel access doors for normal entry and exit conditions.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS is common to Unit 1 and 2 and consists of two independent subsystems. The power supplies for the common portions of the subsystems are from Unit 1 safeguard busses, therefore the inoperability of these Unit 1 supplies are addressed in the SGTS ACTION statements in order to ensure adequate onsite power sources to SGTS for its Unit 2 function during a loss of offsite power event. The allowable out of service times are consistent with those in the Unit 1 Technical Specifications for SGTS and AC electrical power supply out of service condition combinations.

SECONDARY CONTAINMENT (Continued)

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of 5764 ± 10% cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHRSW and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The CREFAS is common to Units 1 and 2 and consists of two independent subsystems. The power supplies for the system are from Unit 1 Safeguard busses, therefore, the inoperability of these Unit 1 supplies are addressed in the CREFAS ACTION statements in order to ensure adequate onsite power sources to CREFAS during a loss of offsite power event. The allowable out of service

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

times are consistent with those in the Unit 1 Technical Specifications for CREFAS and AC electrical power supply out of service condition combinations.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, the CREFAS System provides protection from radiation, smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4

2. UFSAR Section 9.5

3. Regulatory Guide 1.196

4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.

5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RCIC System and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.7.3.a.2 is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

3/4.7.4 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 nonsafety-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.

Snubbers are classified and grouped by design and manufacturer but not by size. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip, and 100-kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purposes of this Technical Specification would be of a different type, as would hydraulic snubbers from either manufacturer.

A list of individual snubbers with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each snubber shall be determined and approved by the Plant Operations Review Committee. The determination shall be based upon the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.), and the recommendations of Regulatory Guides 8.8 and 8.10. The addition or deletion of any snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection schedule is based on the number of unacceptable snubbers found during the previous inspection in proportion to the sizes of the various snubber populations or categories. The visual inspection interval is based on a fuel cycle of up to 24 months and may be as long as two fuel cycles or 48 months depending on the number of unacceptable snubbers found during the previous visual inspection. The visual inspection schedule provides confidence that a constant level of snubber protection is being maintained and generally allows performance of visual inspections and corrective actions during plant outages. 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 required a shorter inspection interval will override the previous schedule.

A snubber is considered inoperable if it fails the acceptance criteria of the visual inspection.

SNUBBERS (Continued)

To provide assurance of snubber functional reliability one of two functional testing methods is used with the stated acceptance criteria:

1. Functionally test 13.3% sample of a type of snubber with an additional 1/2 sample tested for each functional testing failure, or

2. Functionally test 37 snubbers and determine sample acceptance using Figure 4.7.4-1.

Functional Testing sample plans are based on ASME/ANSI OMc-1990 Addenda to ASME/ANSI OM-1987, Part 4.

Figure 4.7.4-1 was developed using "Wald's Sequential Probability Ratio Plan" as described in Quality Control and Industrial Statistics" by Acheson J. Duncan.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (i.e., newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life.

3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e,, sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

SEALED SOURCE CONTAMINATION (Continued)

The testing frequency for start-up sources and fission detectors is based upon physical limitations in leak testing. For example, the Californium 252 start-up neutron source must be leak tested by the manufacturer remotely in a hot cell facility. Due to the physical design of this source, a six month frequency for contamination testing provides reasonable assurance that the radioactive material is properly contained.

3/4 7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformers 8A/8B) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 8A/8B transformers. Additionally, the Unit Auxiliary Buses do not transfer to the 8A/8B transformers; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Onsite A.C. operability requirements for common systems such as CREFAS, SGTS, RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all remaining required systems, subsystems, trains, components, and devices, that depend on the OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators are inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action i, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, "Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation," dated September 27, 1993.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as ≤ 2 amps, and for Divisions 3 and 4 as ≤ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, (i.e., greater than the minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Supplies, March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450-1995.

This Surveillance Requirement states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained the Actions of LCO 3.8.2.1, Action b., are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

THIS PAGE INTENTIONALLY LEFT BLANK

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core unloading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

Inadvertent criticality is prevented by the refueling interlocks that block unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn or withdrawal of a rod from the core while the grapple is over the core and loaded with fuel). The hoist loaded values identified in Sections 4.9.6.1b and 4.9.6.1c support the refueling interlock logic by ensuring that the hoist fuel loaded switches function with a load lighter than the weight of a single fuel assembly in water. Load values represent fuel (load) on the grapple. The values of 485 +/- 50 pounds and 550 + 0, -115 pounds are both less than the weight of a single fuel assembly in water attached to the grapple. These load values ensure that as soon as a fuel assembly is grappled and lifted, the refueling interlocks (control rod block and bridge motion interlock) are enforced as required. The hoist load weighing system is compensated for mast weight to ensure that lifting of components other than fuel assemblies (e.g., blade guides) do not cause inadvertent control rod blocks or bridge motion stops.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication. Management of gas voids is important to RHR Shutdown Cooling Subsystem OPERABILITY.

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION (Continued)

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensible gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to placing the system in operation when in OPCON 5. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System that is aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. An RHR Shutdown Cooling sub-system that is already in operation at the time of entry into the APPLICABILITY is OPERABLE. For an idle RHR Shutdown Cooling subsystem, the surveillance is met through the performance of the operating procedures that place the RHR Shutdown Cooling subsystem in service.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

This special test exception permits relief from the requirements for a minimum count rate while loading the first 16 fuel bundles to allow sufficient source-to-detector coupling such that minimum count rate can be achieved on an SRM. This is acceptable because of the significant margin to criticality while loading the initial 16 fuel bundles.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F and less than or equal to 212°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 2 and 3. Operations with the Potential for Draining the Vessel, Core alterations, and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4 11.2.2 through 3/4 11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.2.5 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the main condenser offgas treatment system is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen below its flammability limit provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.2.7, 3/4.11.3, and 3/4.11.4 (Deleted) - INFORMATION FROM THESE SECTIONS RELOCATED TO THE ODCM OR PCP.

Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS SECTION
HAS BEEN RELOCATED TO THE ODCM.
BASES PAGE B 3/4 12-2 HAS BEEN
INTENTIONALLY OMITTED.

THIS PAGE INTENTIONALLY LEFT BLANK