TABLE OF CONTENTS

CHAPTER 18.0

RESPONSE TO NUREG-0737
CLARIFICATION OF TMI ACTION
PLAN REQUIREMENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

CHAPTER 18 - LIST OF FIGURES

*Refer to Section 1.6 and Table 1.6-3. Controlled drawings were removed from the USAR at Revision 17 and are considered incorporated by reference.

CHAPTER 18.0

18.0 RESPONSE TO NUREG-0737, "CLARIFICATION OF TMI ACTION PLAN REQUIREMENTS"

The following discussion of the SNUPPS response to NUREG-0737 is subdivided into three sections: 18.1, Operational Safety; 18.2, Siting and Design; and 18.3, Emergency Preparations and Radiation Protection. Unless otherwise noted, the subsections presenting the NRC guidance are verbatim quotes from NRC documents.

Information in the sections listed below is historical and reflects conditions at the time of plant licensing. This material will not be updated as a whole as it establishes the conditions relevant to initial plant siting and design. Changes to facilities or conditions will be reviewed and updated only when potential hazards not previously analyzed are identified.

18.2.5
18.2.12
18.2.13.2 paragraph 2 2.d.
18.2.13.2 paragraph 2 3.
18.2.13.2 paragraph 2 4.d.
18.2.13.2 paragraph 2 4.e. 1)
18.2.13.2 paragraph 2 4.e. 2)
18.2.13.2 paragraph 2 7.
18.2.13.2 paragraph 2 8.
18.2.13.2 paragraph 2 9.

18.0.1 COMPLIANCE WITH REVSED REGULATIONS 10CFR50 AND 10CFR52 (NRC-2008-0122) RIN 3150-AI10, “ENHANCEMENTS TO EMERGENCY PREPAREDNESS REGULATIONS” [EFFECTIVE 12/23/2011] AFFECTING RESPONSE TO NUREG-0737

Section 18.4 provides a discussion for compliance with revised regulations 10CFR50 and 10CFR52 pertaining to “Enhancements to Emergency Preparedness Regulations” applicable to the Emergency Operations Facility (EOF) and Alternate Technical Support Center (TSC). The compliance with the revised regulations may enhance or supersede previous information provided in section 18.3 applicable to the EOF and Alternate TSC for the response to NUREG-0737. The comprehensive emergency plan provides the implementation of the revised objectives and requirements of 10CFR50, Appendix E, applicable to the EOF and Alternate TSC.

18.1 OPERATIONAL SAFETY

18.1.1 SHIFT TECHNICAL ADVISOR (I.A.1.1)

18.1.1.1 NRC Guidance Per NUREG-0737

Position

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the STAs that pertain to the engineering aspects of ensuring safe operations of the plant, including the review and evaluation of operating experience.

Clarification

The staff letter of October 30, 1979 from H. R. Denton to All Operating Nuclear Power Plants clarified the short-term STA requirements. The letter indicated that the STAs must have completed all training by January 1, 1981. This paper confirms these requirements and requests additional information.

The need for the STA position may be eliminated when the qualifications of the shift supervisors and senior operators have been upgraded and the man-machine interface in the control room has been acceptably upgraded. However, until these long term improvements are attained, the need for an STA program will continue.

The staff has not yet established the detailed elements of the academic and training requirements of the STA beyond the guidance given in its October 30, 1979 letter. Nor has the staff made a decision on the level of upgrading required for licensed operating personnel and the man-machine interface in the control room that would be acceptable for eliminating the need of an STA. Until these requirements for eliminating the STA position have been established, the staff continues to require that, in addition to the staffing requirements specified in its July 31, 1980 letter (as revised by item I.A.1.3 of this report), an STA be available for duty on each operating shift when a plant is being operated in Modes 1-4 for a PWR and Modes 1-3 for a BWR. At other times, an STA is not required to be on duty.

Since the October 30, 1979 letter was issued, several efforts have been made to establish, for the longer term, the minimum level of experience, education, and training for STAs. These efforts include work on the revision to ANS-3.1, work by the Institute of Nuclear Power Operations (INPO), and internal staff efforts.

INPO has issued a document entitled "Nuclear Power Plant Shift Technical Advisor--Recommendations for Position Description, Qualifications, Education, and Training." A copy of Revision 0 of this document, dated April 30, 1980, is attached as Appendix C [to NUREG-0737]. Sections 5 and 6 of the INPO document describe the education, training, and experience requirements for STAs. The NRC staff finds that the descriptions set forth in Sections 5 and 6 of Revision 0 to the INPO document are an acceptable approach for the selection and training of personnel to staff the STA positions. [Note: This should not be interpreted to mean that this is an NRC requirement at this time. The intent is to refer to the INPO document as acceptable for interim guidance for a utility in planning its STA program over the long term (i. e., beyond the January 1, 1981 requirement to have STAs in place in accordance with the qualification requirements specified in the staff's October 30, 1979 letter).]

No later than January 1, 1981, all licensees of operating reactors shall provide this office with a description of their STA training program and their plans for requalification training. This description shall indicate the level of training attained by STAs by January 1, 1981 and demonstrate conformance with the qualification and training requirements in the October 30, 1979 letter. Applicants for operating licenses shall provide the same information in this application, or amendments thereto, on a schedule consistent with the NRC licensing review schedule.

No later than January 1, 1981, all licensees of operating reactors shall provide this office with a description of their long-term STA program, including qualification, selection criteria, training plans, and plans, if any, for the eventual phaseout of the STA program. (Note: The description shall include a comparison of the licensee/applicant program with the above-mentioned INPO document. This request solicits industry views to assist NRC in establishing long-term improvements in the STA program. Applicants for operating licenses shall provide the same information in their application, or amendments thereto, on a schedule consistent with the NRC licensing review schedule.)

18.1.1.2 The Operating Agent Response

[Note: The remainder of Section 18.1.1 is included for historical purposes, however, the operating agent’s conformance with NUREG-0737, Item I.A.1.1, is as specified by the Commission Policy Statement on Engineering Expertise on Shift.]

General

The NRC issued a Policy Statement on Engineering Expertise on Shift in October 1985. The Commission Policy Statement on Engineering Expertise on shift is discussed in sections 13.2.1.1.3.1 and 13.2.1.1.3.2. The Policy Statement permits either of two options to be used to implement long term goals towards upgrading the qualifications and training of operating staffs. These are Option 1: Combined SRO/STA Position and Option 2: Continued Use of STA Position. Either of these options may be used to meet the requirements of NUREG-0737, Item I.A.1.1. Also, either Option 1 or 2 may be used on each shift. The complete requirements for the options are as follows:

Option 1: Combined SRO/STA Position

This option is satisfied by assigning an individual with the following qualifications to each operating shift crew as one of the SROs (preferably the Shift Manager) required by 10 CFR 50.54(m)(2)(i):

a. Licensed as a senior operator on the nuclear power unit(s) to which assigned and;

b. Meets the STA training criteria of NUREG-0737, Item I.A.1.1, and one of the following educational alternatives:

    1. Bachelor's degree in engineering from an accredited institution;

    2. Professional Engineer's license obtained by the successful completion of the PE examination;

    3. Bachelor's degree in engineering technology from an accredited institution, including course work in the physical, mathematical, or engineering sciences; or

    4. Bachelor's degree in a physical science from an accredited institution, including course work in the physical, mathematical, or engineering sciences.

Option 2: Continued Use of STA Position

This option is satisfied by placing on each shift a dedicated Shift Technical Advisor (STA) who meets the STA criteria of NUREG-0737, Item I.A.1.1. The STA should assume an active role in shift activities. For example, the STA should review plant logs, participate in shift turnover activities, and maintain an awareness of plant configuration and status.

As stated in NUREG-0737 and the background to the NRC Policy Statement (discussed below), the requirement for an STA qualified person in the power plant in addition to an SRO licensed Shift Manager was intended to be a temporary requirement until the qualifications of the Shift Manager and senior operators are upgraded and control boards are reviewed and modified to make information and controls more useful to the operators. This is consistent with the industry consensus established by INPO standard GPG-01, "Nuclear Power Plant Shift Technical Advisor Position Description Qualifications, Education and Training" which refers to the fact of this position being "eliminated" when certain additional actions are completed. The December 17, 1981 approved copy of ANSI/ANS 3.1 also referred to this position as "interim."

The NRC staff has completed the review of the WCGS operator qualification program developed to address NUREG-0737, Item I.A.1.1. The program and NRC staff review results are discussed below.

Man-Machine Interface Upgrade

The man-machine interface in the control room has been upgraded by means of an extensive control room design review which included human factors input. For a detailed description of this effort refer to Section 18.1.16 and 18.1.17.

Operator Qualification Upgrade

Operator qualification upgrading in accordance with NUREG-0737, Item I.A.1.1 is discussed in Section 13.2.1.1.3.

The NRC staff, in SER Supplement 5, noted that if the Kansas State University adopted a Bachelor of Science Degree in Engineering Technology with a Nuclear Option program, completion of the requirements for this degree would achieve the necessary engineering expertise on shift. The program, which involves over

80 semester hours of college level credit, has been inaugurated as discussed in Section 13.2.1.1.3, Item 1.c. The schedule for completion of this training is provided in KMLNRC 85-210, dated September 3, 1985.

In the Fall of 1992, WCNOC suspended the implementation of its operator Baccalaureate program. In place of this program, WCNOC implemented a Shift Engineer Program. The Shift Engineers meet the academic and training requirements to perform the duties of STA.

Training requirements for the STA are described in sections 13.2.1.1.3.2 and 13.2.2.12.

WCNOC has either a Senior Reactor Operator or a Shift Engineer who meets the STA training criteria of NUREG-0737, assigned to each of the Control Room Operating Crews when the reactor is in MODES 1-4.

18.1.1.3 *Conclusion*

The Operating Agent's actions to upgrade qualification of operating staff and the man-machine interface for control room personnel are consistent with the intent and specifics of the long-term resolution of Item I.A.1.1 of NUREG-0737.

18.1.2 SHIFT SUPERVISOR'S ADMINISTRATIVE DUTIES (I.A.1.2)

18.1.2.1 NRC Guidance Per NUREG-0578

Position

1. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for the safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

2. Plant procedures shall be reviewed to ensure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room, relative to other plant management personnel. Particular emphasis shall be placed on the following:

    a. The responsibility and authority of the shift supervisor when on duty in the control room shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times. The principle shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

b. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

c. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

3. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function the shift supervisor is to provide for ensuring safety.

4. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for ensuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

18.1.2.2 The Operating Agent Response

The President and Chief Executive Officer issues and reviews on an annual basis a management directive which emphasizes the responsibilities of the Shift Manager. The directive clearly emphasizes the command responsibilities of the Shift Manager during all normal and emergency operating conditions.

As discussed in Section 13.1.2.2.1, plant administrative procedures also define the duties, responsibilities, and authority of Shift Managers, Control Room Supervisors, and Reactor Operators (ROs). Licensed operators are trained in accordance with training programs which meet 10 CFR 55 criteria. Administrative procedures further define the line of command for the Shift Manager. The Shift Manager reports to the Superintendent Operations during normal operations and to the Duty/Call Superintendent during an emergency. The Shift Manager is the senior licensed management representative onsite on back shifts. The Control Room Supervisor, who reports to the Shift Manager, is in direct charge of the control room during normal operation, in order to allow the Shift Manager to direct his attention to overall plant operation for which he is responsible. In the event of the absence of the Shift Manager from the control room the control room command function is established in accordance with Technical Specifications.

In conjunction with the annual review of the management directive defining the Shift Manager’s authority and responsibilities, the President and Chief Executive Officer is provided an assessment of the administrative duties undertaken by the Shift Manager. If these duties are found to detract from the Shift Manager’s responsibility for safe operation of the plant, they will be delegated to other appropriate members of the station staff.

18.1.2.3 Conclusion

The Operating Agent's commitment to the establishment and annual review of management directives defining the responsibilities and authority of the Shift Manager and to the implementation of training programs in accordance with 10 CFR Part 55 meet the specifics of Item I.A.1.2 in NUREG-0737.

18.1.3 SHIFT MANNING (I.A.1.3)

18.1.3.1 NRC Guidance Per NUREG-0737

Position

This position defines shift manning requirements for normal operation. The letter of July 31, 1980 from D. G. Eisenhut to all power reactor licensees and applicants sets forth the interim criteria for shift staffing (to be effective pending general criteria that will be the subject of future rule-making). Overtime restrictions were also included in the July 31, 1980 letter.

Clarification (as modified by NRC Generic Letter 82-12)

Licensees of operating plants and applicants for operating licenses shall include in their administrative procedures (required by license conditions) provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to man the operational shifts are readily available in the event of an abnormal or emergency situation.

These administrative procedures shall also set forth a policy, the objective of which is to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls established should assure that, to the extent practicable, personnel are not assigned to shift duties while in a fatigued condition that could significantly reduce their mental alertness or their decision making ability. The controls shall apply to the plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, auxiliary operators, health physicists, and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours", dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions. The guidance contained in IE Circular No. 80-02 was amended by the July 31, 1980 letter. In turn, the overtime guidance of the July 31, 1980 letter was revised in Section I.A.1.3 of NUREG-0737. The NRC has issued a policy statement which further revises the overtime guidance as stated in NUREG-0737. This guidance is as follows:

Enough plant operating personnel should be employed to maintain adequate shift coverage without routine heavy use of overtime. The objective is to have operating personnel work a normal 8-hour day, 40-hour week while the plant is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis, the following guidelines shall be followed:

a. An individual should not be permitted to work more than 16 hours straight (excluding shift turnover time).

b. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any seven day period (all excluding shift turnover time).

c. A break of at least eight hours should be allowed between work periods (including shift turnover time).

d. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on shift.

Recognizing that very unusual circumstances may arise requiring deviation from the above guidelines, such deviation shall be authorized by the plant manager or his deputy, or higher levels of management. The paramount consideration in such authorization shall be that significant reductions in the effectiveness of operating personnel would be highly unlikely. Authorized deviations to the working hour guidelines shall be documented and available for NRC review.

In addition, procedures are encouraged that would allow licensed operators at the controls to be periodically relieved and assigned to other duties away from the control board during their tours of duty.

Operating license applicants shall complete these administrative procedures before fuel loading. Development and implementation of the administrative procedures at operating plants will be reviewed by the Office of Inspection and Enforcement beginning October 1, 1982.

See Section III.A.1.2 [of NUREG-0737] for minimum staffing and augment capabilities for emergencies.

18.1.3.2 The Operating Agent Response

Shift staffing is discussed in Section 13.1. The Operating Agent has an administrative procedure governing shift manning and movement of key individuals. Unexpected absences are also addressed in the procedure. Additional information on staffing requirements is contained in the WCGS Technical Specifications and in the Technical Requirements Manual.

In addition, the Operating Agent administrative procedures discuss the overtime restrictions addressed in NUREG-0737 as revised by Generic Letter 82-12. The Operating Agent has committed to comply with these limitations, except in cases where special circumstances require additional coverage. Any such exceptions are approved by the Plant Manager or his designated alternate, with appropriate documentation.

WCGS complies with 10 CFR 26, Subpart I, “Managing Fatigue.” Procedures and Programs affected by 10 CFR 26, Subpart I, has been updated to ensure compliance with the rule.

18.1.3.3 Conclusion

The Operating Agent's commitments to a minimum shift complement and the additional commitment to observing the overtime restrictions listed in NUREG-0737, as revised by Generic Letter 82-12, meet the NRC's guidance.

18.1.4 IMMEDIATE UPGRADING OF REACTOR OPERATOR AND SENIOR REACTOR OPERATOR TRAINING AND QUALIFICATIONS (I.A.2.1)

18.1.4.1 NRC Guidance Per NUREG-0737

Position

Effective December 1, 1980, an applicant for a SRO license will be required to have been a licensed operator for 1 year.

Clarification

Applicants for SRO either come through the operations chain (C operator to B operator to A operator, etc.) or are degree-holding staff engineers who obtain licenses for backup purposes.

In the past, many individuals who came through the operator ranks were administered SRO examinations without first being an operator. This was clearly a poor practice and the letter of March 28, 1980 requires reactor operator experience for SRO applicants.

However, NRC does not wish to discourage staff engineers from becoming licensed SROs. This effort is encouraged because it forces engineers to broaden their knowledge about the plant and its operation.

In addition, in order to attract degree-holding engineers to consider the Shift Supervisor's job as part of their career development, NRC should provide an alternate path to holding an operator's license for 1 year.

The track followed by a high-school graduate (a nondegreed individual) to become an SRO would be 4 years as a control room operator, at least one of which would be as a licensed operator, and participation in an SRO training program that includes 3 months onshift as an extra person.

The track followed by a degree-holding engineer would be, at a minimum, 2 years of responsible nuclear power plant experience as a staff engineer, participation in an SRO training program equivalent to a cold applicant training program, and 3 months onshift as an extra person in training for an SRO position.

Holding these positions ensures that individuals who will direct the licensed activities of licensed operators have had the necessary combination of education, training, and actual operating experience prior to assuming a supervisory role at that facility.

The staff realizes that the necessary knowledge and experience can be gained in a variety of ways. Consequently, credit for equivalent experience should be given to applicants for SRO licenses.

Applicants for SRO licenses at a facility may obtain their 1-year operating experience in a licensed capacity (operator or senior operator) at another nuclear power plant. In addition, actual operating experience in a position that is equivalent to a licensed operator or senior operator at military propulsion reactors will be acceptable on a one-for-one basis. Individual applicants must document this experience in their individual applications in sufficient detail so that the staff can make a finding regarding equivalency.

Applicants for SRO licenses who possess a degree in engineering or applicable sciences are deemed to meet the above requirement, provided they meet the requirements set forth in Sections A.1.a. and A.2. in enclosure l in the letter from H. R. Denton to all power reactor applicants and licensees, dated March 28, 1980, and have participated in a training program equivalent to that of a cold senior reactor operator applicant.

NRC has not imposed the 1-year experience requirement on cold applicants for SRO licenses. Cold applicants are to work on a facility not yet in operation; their training programs are designed to supply the equivalent of the experience not available to them.

18.1.4.2 The Operating Agent Response

As discussed in Section 13.2, the Operating Agent has committed to conduct its licensed operator training and requalification programs in accordance with the requirements of 10 CFR Part 55. In addition, the Operating Agent complies with training and qualification guidance delineated in Regulatory Guide 1.8, Revision 2, Personnel Selection and Training, which references ANS-3.1-1981.

Additional discussion of the Operating Agent's commitments relative to training and requalification programs is presented in Section 18.1.6.

18.1.4.3 Conclusion

The Operating Agent has committed to comply with 10 CFR Part 55 requirements for operator licensing and requalification programs and to follow recommendations contained in supplementary industry guidance.

18.1.5 ADMINISTRATION OF TRAINING PROGRAMS (I.A.2.3)

18.1.5.1 NRC Guidance Per NUREG-0737

Position

Pending accreditation of training institutions, licensees and applicants for operating licenses will assure that training center and facility instructors who teach systems, integrated responses, transient, and simulator courses demonstrate SRO qualifications and be enrolled in appropriate requalification programs.

Clarification

The above position is a short-term position. In the future, accreditation of training institutions will include review of the procedure for certification of instructors. The certification of instructors may, or may not, include successful completion of an SRO examination.

The purpose of the examination is to provide the NRC with reasonable assurance during the interim period that instructors are technically competent.

The requirement is directed to permanent members of training staff who teach the subjects listed above, including members of other organizations who routinely conduct training at the facility. There is no intention to require guest lecturers who are experts in particular subjects (reactor theory, instrumentation, thermodynamics, health physics, chemistry, etc.) to successfully complete an SRO examination. Nor is it intended to require a system expert, such as the instrument and control supervisor teaching the control rod drive system, to complete an SRO examination.

18.1.5.2 <u>The Operating Agent Response</u>

This material is discussed in Section 13.2.1.2.2, 13.2.2.10.3 and 13.2.3.4.

All operator license program instructors are required to participate in selected requalification program topics, for licensed operators. In addition, licensed training instructors engaged in operator training participate in the following activities:

- Periodic onshift assignments

- Review of facility operating and emergency operating procedures as they are developed

- Participation in instructor certification programs, such as those proposed by INPO.

18.1.5.3 Conclusion

The Operating Agent has committed to comply with NRC guidance relative to the training and qualifications of nuclear training staff, and meets the legal requirements of 10 CFR Part 55 where SRO licenses are required.

18.1.6 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS (I.A.3.1)

18.1.6.1 NRC Guidance Per NUREG-0737

Position

Simulator examinations will be included as part of the licensing examinations.

Clarification

The clarification does not alter the staff's position regarding simulator examinations.

The clarification does provide additional preparation time for utility companies and NRC to meet the examination requirements as stated. A study is under way to consider how similar a nonidentical simulator should be for a valid examination. In addition, present simulators are fully booked months in advance.

Application of this requirement was stated on June 1, 1980 to applicants where a simulator is located at the facility. Starting October 1, 1981, simulator examinations will be conducted for applicants of facilities that do not have simulators at the site.

NRC simulator examinations normally require 2 to 3 hours. Normally, two applicants are examined during this time period by two examiners.

Utility companies should make the necessary arrangements with an appropriate simulator training center to provide time for these examinations. Preferably, these examinations should be scheduled consecutively with the balance of the examination. However, they may be scheduled no sooner than 2 weeks prior to and no later than 2 weeks after the balance of the examination.

18.1.6.2 The Operating Agent Response

The Operating Agent has a full scope simulator near the plant site. The simulator is used as part of the licensing examinations. For further direction as to the use of the simulator see Section 13.2.

18.1.6.3 Conclusion

The Operating Agent has committed to NUREG-0737 guidance with regard to the NRC's revised scope and criteria for license examinations. In addition, the Operating Agent has incorporated simulator examinations into it's training program. These commitments comply fully with the NRC guidance as stated in NUREG-0737 relative to licensing examinations.

18.1.7 EVALUATION OF ORGANIZATION AND MANAGEMENT (I.B.1.2)

18.1.7.1 NRC Guidance Per NUREG-0694 and NUREG-0737

Position

The licensee organization shall comply with the findings and requirements generated in an interoffice NRC review of licensee organization and management. The review will be based, in part, on an NRC document entitled "Draft Criteria for Utility Management and Technical Competence." The first draft of this document was dated February 25, 1980. The current draft was issued for interim use and public comment in September 1980 as NUREG-0731, "Guidelines for Utility Management Structure and Technical Resources." These draft guidelines address the organization, resources, training, and qualifications of plant staff and management (both onsite and offsite) for routine operations and the resources and activities (both onsite and offsite) for accident conditions.

The licensee shall establish a group that is independent of the plant staff but is assigned onsite to perform independent reviews of plant operational activities and a capability for evaluation of operating experiences of nuclear power plants.

Organizational changes are to be implemented on a schedule to be determined prior to fuel loading.

Corporate management of the utility-owner of a nuclear power plant shall be sufficiently involved in the operational phase activities, including plant modifications, to ensure a continual understanding of plant conditions and safety considerations. Corporate management shall establish safety standards for the operation and maintenance of the nuclear power plant. To these ends, each utility-owner shall establish an organization, parts of which shall be located onsite, to: perform independent reviews and audits of plant activities; provide technical support to the plant staff for maintenance, modifications, operational problems, and operational analysis; and aid in the establishment of programmatic requirements for plant activities.

The licensee shall establish an integrated organizational arrangement to provide for the overall management of nuclear power plant operations. This organization shall provide for clear management control and effective lines of authority and communication between the organizational units involved in the management, technical support, and operation of the nuclear unit.

The key characteristics of a typical organization arrangement are:

a. Integration of all necessary functional responsibilities under a single responsible head.

b. The assignment of responsibility for the safe operation of the nuclear power plant(s) to an upper level executive position.

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operation.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities, including maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. ISEG will then be in a position to advise utility management on the overall quality and safety of operations. ISEG need not perform detailed audits of plant operations and shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

Clarification

The new ISEG shall not replace the plant operations review committee (PORC) and the utility's independent review and audit group as specified by current staff guidelines (Standard Review Plan, Regulatory Guide 1.33, Standard Technical Specifications). Rather, it is an additional independent group of a minimum of five dedicated, full-time engineers, located onsite, but reporting offsite to a corporate official who holds a high-level, technically oriented position that is not in the management chain for power production. The ISEG will increase the available technical expertise located onsite and will provide continuing, systematic, and independent assessment of plant activities. Integrating the STAs into the ISEG in some way would be desirable in that it could enhance the group's contact with and knowledge of day-to-day plant operations and provide additional expertise. However, the STA on shift is necessarily a member of the operating staff and cannot be independent of it.

It is expected that the ISEG may interface with the quality assurance (QA) organization, but preferably should not be an integral part of the QA organization.

The functions of the ISEG require daily contact with the operating personnel and continued access to plant facilities and records. The ISEG review functions can, therefore, best be carried out by a group physically located onsite. However, for utilities with multiple sites, it may be possible to perform portions of the independent safety assessment function in a centralized location for all the utilities' plants. In such cases, an onsite group still is required, but it may be slightly smaller than would be the case if it were performing the entire independent safety assessment function. Such cases will be reviewed on a case-by-case basis.

At this time, the requirement for establishing an ISEG is being applied only to applicants for operating licenses in accordance with Action Plan Item I.B.1.2. The staff intends to review this activity in about a year to determine its effectiveness and to ascertain whether changes are required. Applicability to operating plants will be considered in implementing long-term improvements in organization and management for operating plants (Action Plan Item I.B.1.1).

18.1.7.2 The Operating Agent Response

The Operating Agent performs the ISEG functions. The Vice President Engineering and Site Vice President, through ownership of ISEG function implementing procedures, are responsible for the ISEG functions. Refer to Table 18.1-1, ISEG Function Cross Reference, for ISEG function to implementing procedure details. Persons performing the ISEG functions have direct access to the President and Chief Executive Officer for resolution of any areas in question. The ISEG functions are performed by degreed individuals with specific experience and training in one or more of the following disciplines: nuclear engineering, mechanical engineering, electrical engineering, chemistry/radiological controls, and nuclear operations. The persons performing the ISEG functions are located physically onsite at WCGS.

The ISEG functions include independent review of plant activities and operating experience information. The ISEG function includes performing independent technical evaluations of plant maintenance, modifications, operational problems, and operational analysis activities. The ISEG function also includes developing appropriate detailed recommendations for revisions to procedures or modifications to equipment as may be necessary. The ISEG functions include the survey of plant maintenance operations and test activities to provide verification independent of the plant operating staff that maintenance, operations and test activities are performed in accordance with established procedures. Table 18.1-1 provides a cross-reference of the ISEG functions to the implementing procedures.

Relative to organization and management structure, the Operating Agent has established an Operations organization whose authorities and responsibilities are consistent with NRC guidance.

18.1.7.3 Conclusion

The Operating Agent has committed to the NUREG-0737 guidance relative to the establishment of functions and activities to satisfy an onsite independent safety engineering group and has established an Operations organization dedicated to the support of WCGS.

18.1.8 GUIDANCE FOR THE EVALUATION AND DEVELOPMENT OF PROCEDURES FOR TRANSIENTS AND ACCIDENTS (I.C.1)

18.1.8.1 NRC Guidance Per NUREG-0737

Position

In letters of September 13 and 27, October 10 and 30, and November 9, 1979, the Office of Nuclear Reactor Regulation required licensees of operating plants, applicants for operating licenses, and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, including procedures for operating with natural circulation conditions, and to conduct operator retraining (see also Item I.A.2.1). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980, and implementation of procedures and retraining were to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions are being developed. In the course of the review of these matters on Babcock and Wilcox (B&W)-designed plants, the staff will follow up on the bulletin and orders matters relating to analysis methods and results, as listed in NUREG-0660, Appendix C (see Table C.1, items 3, 4, 16, 18, 24, 25, 26, 27; Table C.2, items 4, 12, 17, 18, 19, 20; and Table C.3, items 6, 35, 37, 38, 41, 47, 55, 57).

Clarification

The letters of September 13 and 27, October 10 and 30, and November 9, 1979 required that procedures and operator training be developed for transients and accidents. The initiating events to be considered should include the events presented in the FSAR: loss of instrumentation buses and natural phenomena such as earthquakes, floods, and tornadoes. The purpose of this paper is to clarify the requirements and add additional requirements for the reanalysis of transients and accidents and inadequate core cooling.

Based on staff reviews to date, there appear to be some recurring deficiencies in the guidelines being developed. Specifically, the staff has found a lack of justification for the approach used (i.e., symptom-, event-, or function-oriented) in the developing diagnostic guidance for the operator and in procedural development. It has also been found that although the guidelines take implicit credit for the operation of many systems or components, they do not address the availability of these systems under expected plant conditions nor do they address corrective or alternative actions that should be performed to mitigate the event should these systems or components fail.

The analyses conducted to date for guideline and procedure development contain insufficient information to assess the extent to which multiple failures are considered. NUREG-0578 concluded that the single-failure criterion was not considered appropriate for guideline development and called for the consideration of multiple failures and operator errors. Therefore, the analyses that support guideline and procedure development should consider the occurrences of multiple and consequential failures. In general, the sequence of events for the transients and accidents and inadequate core cooling analyzed should postulate multiple failures such that, if the failures were unmitigated, conditions of inadequate core cooling would result.

Examples of multiple failure events include:

1. Multiple tube ruptures in a single steam generator and tube rupture in more than one steam generator.

2. Failure of main and auxiliary feedwater.

3. Failure of high-pressure reactor coolant makeup system.

4. An anticipated transient without scram (ATWS) event following a loss of offsite power, stuck-open relief valve or safety/relief valve, or loss of main feedwater.

5. Operator errors of omission or commission.

The analyses should be carried out far enough into the event to ensure that all relevant thermal/hydraulic/neutronic phenomena are identified (e.g., upper head voiding due to rapid cooldown, steam generator stratification). Failures and operator errors during the long-term cooldown period should also be addressed.

The analyses should support development of guidelines that define a logical transition from the emergency procedures into the inadequate core cooling procedure, including the use of instrumentation to identify inadequate core cooling conditions. Rationale for this transition should be discussed. Additional information that should be submitted includes:

1. A detailed description of the methodology used to develop the guidelines;

2. Associated control function diagrams, sequence-of-event diagrams, or others, if used;

3. The bases for multiple and consequential failure considerations;

4. Supporting analysis, including a description of any computer codes used; and

5. A description of the applicability of any generic results to plant-specific applications.

Owners' Group or vendor submittals may be referenced as appropriate to support this reanalysis. If Owners' Group or vendor submittals have already been forwarded to the staff for review, a brief description of the submittals and justification of their adequacy to support guideline development is all that is required.

Pending staff approval of the revised analysis and guidelines, the staff will continue the pilot monitoring of emergency procedures described in Task Action Plan Item I.C.8 (NUREG-0660). For PWRs, this will involve review of the loss-of-coolant, steam-generator tube rupture, loss of main feedwater, and inadequate core cooling procedures. The adequacy of each PWR vendor's guidelines will be identified to each NTOL during the emergency-procedure review. Since the analysis and guidelines submitted by the General Electric Company (GE) Owners' Group that comply with the requirements stated above have been reviewed and approved for trial implementation on six plants with applications for operating licenses pending, the interim program for BWRs will consist of trial implementation of these six plants.

Following approval of analysis and guidelines and the pilot monitoring of emergency procedures, the staff will advise all licensees of the adequacy of the guidelines for application to their plants. Consideration will be given to human-factors engineering and system operational characteristics, such as information transfer under stress, compatibility with operator training and control room design, the time required for component and system response, clarity of procedural actions, and control room personnel interactions. When this determination has been made by the staff, a long-term plan for emergency procedure review, as described in Task Action Plan Item I.C.9, will be made available. At that time, the reviews currently being conducted on NTOLs under Item I.C.8 will be discontinued, and the review required for applicants for operating licenses will be as described in the long-term plan. Depending on the information submitted to support development of emergency procedures for each reactor type or vendor, this transition may take place at different times. For example, if the GE guidelines are shown to be effective on the six plants chosen for pilot monitoring, the long-term plan for BWRs may be complete in early 1981. Operating plants and applicants will then have the option of implementing the long-term plan in a manner consistent with their operating schedule, provided they meet the final date required for implementation. This may require a plant that was reviewed for an operating license under Item I.C.8 to revise its emergency procedures again prior to the final implementation date for Item I.C.9. The extent to which the long-term program will include review and approval of plant-specific procedures for operating plants has not been established. Our objective, however, is to minimize the amount of plant-specific procedure review and approval required. The staff believes this objective can be acceptably accomplished by concentrating the staff review and approval on generic guidelines. A key element in meeting this objective is the use of staff-approved generic guidelines and guideline revisions by licensees to develop procedures. For this approach to be effective, it is imperative that, once the staff has issued approval of a guideline, subsequent revisions of the guideline should not be implemented by licensees until reviewed and approved by the staff. Any changes in plant-specific procedures based on unapproved guidelines could constitute an unreviewed safety issue under 10 CFR 50.59. Deviations from this approach on a plant-specific basis would be acceptable provided the basis is submitted by the licensee for staff review and approval. In this case, deviations from generic guidelines should not be implemented until staff approval is formally received in writing. Interim implementation of analysis and procedures for small-break loss-of-coolant accident and inadequate core cooling should remain on the schedule contained in NUREG-0578, Recommendation 2.1.9.

18.1.8.2 The Operating Agent Response

The NRC issued additional requirements and guidance relative to this issue in Supplement 1 to NUREG-0737 (Generic Letter 82-33). The requirements and guidance in Supplement 1 to NUREG-0737 replaced the corresponding requirements in NUREG-0737.

Through participation in the Westinghouse Owners' Group (WOG), the Operating Agent has been involved in the development of guidelines for accidents that exceed existing design bases and guidelines for inadequate core cooling. Guidelines were submitted to the NRC for review and approval, and after NRC approval was obtained, the guidelines were used for the preparation of generic and/or plant-specific emergency operating and inadequate core cooling procedures.

The WOG has supported development of additional guidelines for comparison to existing guidelines for emergency operation. Events to be reconsidered in the light of NUREG-0737 guidance (i.e., multiple failures) are:

- Large LOCA
- Small LOCA
- Feedline break
- Steamline break
- Steam generator tube rupture

The WOG has completed the expanded guidelines which include the bases for detailed procedures to mitigate inadequate core cooling. The WOG has submitted an update of Westinghouse Topical Report WCAP-9691, which used event tree methodology to extend a review of analyzed accidents to include certain multiple failure considerations. WCAP-9691 was updated to expand the Westinghouse Reference Operating Instruction set through consideration of extended coverage provided by current Emergency Operating

Instruction Guidelines. A significant number of the original WCAP-9691 event sequences were provided with additional "procedural coverage" as a result of the evaluation commissioned by the Owners' Group. By letter dated December 24, 1984, the NRC staff has approved the WOG guidelines (Westinghouse Emergency Response Guidelines, Revision 1) for implementation.

The Operating Agent has developed emergency operating procedures consistent with the WOG guidelines for the events enumerated above. The Operating Agent has evaluated each guideline and developed plant emergency operating procedures specifically applicable to WCGS. Consistent with the requirements of Supplement 1 to NUREG-0737, the Operating Agent has submitted a Procedures Generation Package (PGP) for NRC review. The NRC review of the PGP resulted in submittal of additional information to address the process that was used to derive the instrumentation and control characteristics from the information contained in Revision 1 to the generic guidelines and related background information. These characteristics are defined using function and task analysis methods.

Certain WCGS Emergency Operating procedures were requested for review by the NRC. These procedures were supplied to the NRC.

18.1.8.3 Conclusion

The Operating Agent's commitment to develop emergency operating procedures based on the WOG guidelines is consistent with NUREG-0737, Supplement 1 requirements. The Operating Agent has tailored the Westinghouse guidelines so that they are directly applicable to WCGS. In addition, the Operating Agent has provided emergency operating procedures to Westinghouse for review (see Section 18.1.14) in accordance with NUREG-0737 guidance. Responsibility for the final procedure content and implementation remain with the Operating Agent.

18.1.9 SHIFT RELIEF AND TURNOVER PROCEDURES (I.C.2)

18.1.9.1 NRC Guidance Per NUREG-0578

The licensee shall review and revise, as necessary, the plant procedure for shift and relief turnover to ensure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist:

a. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console. What to check and criteria for acceptable status shall be included in the checklist.

c. Identification of systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement. (This shall be recorded as a separate entry on the checklist.)

2. Checklists or logs shall be provided for completion by the offgoing and oncoming auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by itself could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedures (for example, periodic independent verification of system alignments).

18.1.9.2 The Operating Agent Response

Plant administrative procedures define specific shift relief and turnover procedures for WCGS. Turnover checklists have been developed which include the following information:

a. Control Room relief and turnover:

- Provides means to review plant system alignment for anomalies via critical plant parameter and control panel checks;

- Provides means to determine that onshift activities impacting Technical Specifications have been appropriately documented;

- Provides a clear record of transfer of control room command function from Shift Manager and Control Room Supervisor to their successors on the next shift.

b. Nuclear Station Operator relief and turnover:

- Includes procedures which call for a review of equipment on which maintenance or test activities are being performed.

18.1.9.3 Conclusion

The Operating Agent has satisfied NRC guidance relative to shift relief/turnover procedures through it's commitments to implementation of the described procedures.

18.1.10 SHIFT SUPERVISOR'S RESPONSIBILITIES (I.C.3)

This item is discussed in Section 18.1.2, Shift Supervisor Administrative Duties.

18.1.11 CONTROL ROOM ACCESS (I.C.4)

18.1.11.1 NRC Guidance Per NUREG-0578

Position

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and the predesignated NRC personnel. Provisions shall include the following:

1. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access.

2. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current SRO's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside the control room.

18.1.11.2 The Operating Agent Response

The Operating Agent has administrative procedures which define the line of authority in the control room: the Shift Manager is in overall control room command, and the Control Room Supervisor is in direct control room command. The Operating Agent has implemented additional administrative procedures which define lines of communication and authority for WCGS management "who report to stations both within and outside the control room." During normal plant operations, access to the control room is controlled in accordance with the provisions of the WCGS Security Plan.

In addition, the Radiological Emergency Response Plan for the WCGS clearly indicates that control room access is controlled by the Shift Manager. Access to the Control Room is controlled by the Shift Manager.

18.1.11.3 Conclusion

The Operating Agent has established a procedure which clearly defines the line of authority in the control room during normal and emergency situations. In addition, the Operating Agent has established a procedure that clearly defines restrictions on control room access during normal and emergency conditions. This procedure further defines the authority of the Shift Manager to restrict control room access at all times. These procedures comply with the NRC guidance specified in NUREG-0578.

18.1.12 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO PLANT STAFF (I.C.5)

18.1.12.1 NRC Guidance Per NUREG-0737

Position

In accordance with Task Action Plan I.C.5, Procedures for Feedback of Operating Experience to Plant Staff (NUREG-0660), each applicant for an operating license shall prepare procedures to ensure that operating information pertinent to plant safety originating both within and outside the utility organization is continually supplied to operators and other personnel and is incorporated into training and retraining programs. These procedures shall:

1. Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to operators and other personnel, and the incorporation of such information into training and retraining programs;

2. Identify the administrative and technical review steps necessary in translating recommendations by the operating experience assessment group into plant actions (e.g., changes to procedures, operating orders);

3. Identify the recipients of various categories of information from operating experience (e.g., supervisory personnel, STAs, operators, maintenance personnel, and health physics technicians) or otherwise provide means through which such information can be readily related to the job functions of the recipients;

4. Provide means to assure that affected personnel become aware of and understand information of sufficient importance that should not wait for emphasis through routine training and retraining programs;

5. Assure that plant personnel do not routinely receive extraneous and unimportant information on operating experience in such volume that it would obscure priority information or otherwise detract from overall job performance and proficiency;

6. Provide suitable checks to assure that conflicting or contradictory information is not conveyed to operators and other personnel until resolution is reached; and

7. Provide periodic internal audit to assure that the feedback program functions effectively at all levels.

Clarification

Each utility shall carry out an operating experience assessment function that will involve utility personnel having collective competence in all areas important to plant safety. In connection with this assessment function, it is important that procedures exist to assure that important information on operating experience originating both within and outside the organization is continually provided to operators and other personnel and that it is incorporated into plant operating procedures, training, and retraining programs.

Those involved in the assessment of operating experience will review information from a variety of sources. These include operating information from the licensee's own plant(s), publications such as IE Bulletins, Circulars, Notices, and pertinent NRC or industrial assessments of operating experience. In some cases, information may be of sufficient importance that it must be dealt with promptly (through instructions, changes to operating and emergency procedures, issuance of special changes to operating and emergency procedures, issuance of special precautions, etc.) and must be handled in such a manner to assure that operations management personnel would be directly involved in the process. In many other cases, however, important information will become available which should be brought to the attention of operators and other personnel for their general information to assure continued safe plant operation. Since the total volume of information handled by the assessment group may be large, it is important that assurance be provided that high-priority matters are dealt with promptly and that discrimination is used in the feedback of other information so that personnel are not deluged with unimportant and extraneous information to the detriment of their overall proficiency. It is important, also, that technical reviews be conducted to preclude premature dissemination of conflicting or contradictory information.

18.1.12.2 The Operating Agent Response

Operating experience assessment for WCGS was originally conducted by various groups within the plant and Wichita office staffs who possessed appropriate experience within the area of concern. The program utilized the INPO SEE-IN Program, NRC Office of Inspection and Enforcement Issuances and Licensee Event Reports as input.

The operating experience assessment activities have been upgraded and enlarged to include the above inputs as well as INPO SOERs, SERs, NPRDS, Nuclear Network and information received from vendors and contractors. Input received from these sources is routed to the appropriate coordinator for logging, initial screening and assignment for evaluation. The coordinator also tracks the information through the evaluation and action phases, if necessary.

The administrative system for control of the handling and evaluation of appropriate operating experience data is controlled by division procedures.

18.1.12.3 Conclusion

The Operating Agent's internal programs for the review, evaluation, and dissemination of operating experience gained at WCGS and at other operating facilities fulfill the NRC's NUREG-0737 guidance relative to feedback and evaluation of operating experience.

18.1.13 VERIFY CORRECT PERFORMANCE OF OPERATING ACTIVITIES (I.C.6)

18.1.13.1 NRC Guidance Per NUREG-0737

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Implementation of automatic status monitoring, if required, will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases--one before and one after installation of automatic status monitoring equipment, if required, in accordance with Item I.D.3.

Clarification

Item I.C.6 of the U.S. Nuclear Regulatory Commission Task Action Plan (NUREG-0660) and Recommendation 5 of NUREG-0585 propose requiring that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided. An acceptable program for verification of operating activities is described below.

The American Nuclear Society has prepared a draft revision to ANSI Standard N18.7-1972 (ANS-3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." A second proposed revision to Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," which is to be issued for public comment in the near future, will endorse the latest draft revision to ANS-3.2 subject to the following supplemental provisions:

1. Applicability of the guidance of Section 5.2.6 should be extended to cover surveillance testing in addition to maintenance.

2. In lieu of any designated senior reactor operator (SRO), the authority to release systems and equipment for maintenance or surveillance testing or return-to-service may be delegated to an onshift SRO, provided provisions are made to ensure that the shift supervisor is kept fully informed of system status.

3. Except in cases of significant radiation exposure, a second qualified person should verify correct implementation of equipment control measures, such as the tagging of equipment.

4. Equipment control procedures should include assurance that control room operators are informed of changes in equipment status and the effects of such changes.

5. For the return-to-service of equipment important to safety, a second qualified operator should verify proper system alignment unless functional testing can be performed without compromising plant safety, and can prove that all equipment, valves, and switches involved in the activity are correctly aligned.

Note: A licensed operator possessing knowledge of the systems involved and the relationship of the systems to plant safety would be a "qualified" person. The staff is investigating the level of qualification necessary for other operators to perform these functions.

For plants that have or will have automatic system status monitoring, as discussed in Task Action Plan Item I.D.3, NUREG-0660, the extent of human verification of operations and maintenance activities will be reduced. However, the need for such verification will not be eliminated in all instances.

18.1.13.2 The Operating Agent Response

The Operating Agent has developed specific administrative procedures and utilizes available status monitoring in the control room to control equipment status. The procedures describe the control measures and actions such as locking, tagging, notification, and identification of equipment. The procedures provide for control of equipment to maintain reactor and personnel safety and to avoid unauthorized or inadvertent operation of equipment. As suggested by NUREG-0737, administrative procedures provide instructions for verification of correct performance of operating and surveillance activities. The status monitoring is in the form of position indication in the control room of safety-related valves and breakers or logging of valve/breaker position on the plant computer.

18.1.13.3 Conclusion

The Operating Agent's administrative controls for performance of operating activities satisfy the guidance of NUREG-0737, Item I.C.6.

18.1.14 NSSS VENDOR REVIEW OF PROCEDURES (I.C.7)

18.1.14.1 NRC Guidance Per NUREG-0660

Applicants for near-term operating licenses will be required to obtain NSSS vendor review of their low-power and power-ascension tests, and emergency procedures as a further verification of the adequacy of procedures.

18.1.14.2 The Operating Agent Response

The Operating Agent committed to a review by Westinghouse of specific low-power and power-ascension procedures as a means of further verification of their adequacy. Westinghouse assistance in the preoperational and startup test programs is discussed in

Section 14.2. However, the Operating Agent reserved the right to evaluate any suggested changes resulting from vendor review and, in light of the Operating Agent's ultimate responsibility for the safe operation of WCGS, to make the final determination as to whether any suggested change is warranted.

As discussed in Section 18.1.8.2, the Operating Agent is participating in the Westinghouse Owner's Group activities in which Westinghouse has developed guidelines for preparation of emergency operating procedures. The Operating Agent committed in that section to developing WCGS emergency operating procedures from the generic guidelines. Westinghouse review of the WCGS emergency operating procedures was not only limited to Westinghouse's review and preparation of the generic guidelines. Copies of the emergency procedures were provided to Westinghouse for review.

18.1.14.3 Conclusion

The Operating Agent's actions relative to NSSS vendor review of selected procedures comply with the guidance of NUREG-0737.

18.1.15 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR-TERM OPERATING LICENSE APPLICANTS (I.C.8)

18.1.15.1 NRC Guidance Per NUREG-0737

Position

The NRC will conduct an interdisciplinary and interoffice audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of ac power, steamline break, or steam-generator tube rupture).

The licensee should correct, before full-power operation, any deficiencies in the emergency procedures, as necessary, based on the NRC audit.

18.1.15.2 The Operating Agent Response

The Operating Agent did not object to a pilot review by the NRC of these procedures. However, since the NRC has conducted an indepth review of the WOG guidelines (refer to Section 18.1.8.1), and since the Operating Agent has agreed to use the WOG guidelines, a specific review of the Operating Agent procedures did not appear to be necessary. Based on this reasoning, the NRC, in Supplement 5 to the WCGS Safety Evaluation Report, concluded that Item I.C.8 was resolved.

18.1.15.3 Conclusion

The Operating Agent activities associated with Item I.C.1, Section 18.1.8, comply with the objectives of Item I.C.8 of NUREG-0737.

18.1.16 CONTROL ROOM DESIGN REVIEW (I.D.1)

18.1.16.1 NRC Guidance Per NUREG-0737

Position

In accordance with Task Action Plan I.D.1, Control Room Design Reviews (NUREG-0660), all licensees and applicants for operating licenses will be required to conduct a detailed control room design review to identify and correct design deficiencies. This detailed control room design review is expected to take about a year. Therefore, the Office of Nuclear Reactor Regulation (NRR) requires that those applicants for operating licenses who are unable to complete this review prior to the issuance of a license make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule approved by the NRC for correcting deficiencies. These applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Clarification

NRR is presently developing human engineering guidelines to assist each licensee and applicant in performing detailed control room review. A draft of the guidelines has been published for public comment as NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation." The due date for comments on this draft document was September 29, 1980. NRR will issue the final version of the guidelines as NUREG-0700, by February 1981, after receiving, reviewing, and incorporating substantive public comments from operating reactor licensees, applicants for operating licenses, human factors engineering experts, and other interested parties. NRR will issue evaluation criteria, by July 1981, which will be used to judge the acceptability of the detailed reviews performed and the design modifications implemented.

Applicants for operating licenses who will be unable to complete the detailed control room design review prior to the issuance of a license are required to perform a preliminary control room design assessment to identify significant human factors problems. Applicants will find it of value to refer to draft document NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation," in performing the preliminary assessment. NRR will evaluate the applicants' preliminary assessments, including the performance by NRR of onsite review/audit. The NRR onsite review/audit will be on a schedule consistent with licensing needs and will emphasize the following aspects of the control room:

1. The adequacy of information presented to the operator to reflect plant status for normal operation, anticipated operational occurrences, and accident conditions.

2. The groupings of displays and the layout of panels.

3. Improvements in the safety monitoring and human factors enhancement of controls and control displays.

4. The communications from the control room to points outside the control room, such as the onsite technical support center, remote shutdown panel, and offsite telephone lines, and to other areas within the plant, for normal and emergency operation.

5. The use of direct rather than derived signals for the presentation of process and safety information to the operator.

6. The operability of the plant from the control room with multiple failures of nonsafety-grade and non-seismic systems.

7. The adequacy of operating procedures and operator training with respect to the limitations of instrumentation displays in the control room.

8. The categorization of alarms, with unique definition of safety alarms.

9. The physical location of the Shift Supervisor's office, either adjacent to or within the control room complex.

Prior to the onsite review/audit, NRR will require a copy of the applicant's preliminary assessment and additional information, which will be used in formulating the details of the onsite review/audit.

18.1.16.2 The Operating Agent Response

Supplement 1 to NUREG-0737 (Generic Letter 82-33, dated December 17, 1982) provided guidance and requirements for control room design reviews which superseded previous NRC guidance.

A Preliminary Design Assessment (PDA) of the WCGS control room was performed and the results provided to the NRC (SNUPPS letter dated June 26, 1981). As a result of the PDA activities, four significant actions were undertaken to improve the operator-control board interface and the decision making process:

1. Extensive rearrangement of switches, recorders and indicators was performed to improve location relationship of equipment controls and associated indications.

2. The location of all annunciators was reviewed and an extensive hierarchical arrangement by priority was developed to assist the operator in recognizing independently significant and dependent annunciator alarms.

3. Panels of status and permissive lights have been rearranged into functional groups, and methods of designating different plant safeguards modes have been incorporated to improve the operator's ability to understand and respond to these indications.

4. The Operating Agent, in conjunction with several owners of Westinghouse plants, has developed an extensive Safety Parameter Display System with an ability to display critical parameters, both quantitatively and graphically. The Senior Reactor Operators in the control room have these Safety Parameter Display Systems available to them to monitor plant conditions during any incident (refer to Section 18.1.17).

The original control board design had significant Prairie Island and Ginna plant operating experience input from Northern States Power and Rochester Gas and Electric during the initial design phases and had more extensive use of system mimic-layout than most nuclear plant control boards. The above modifications improved upon one of the better pre-TMI control board designs and results in the control board supplying relevant, easy to comprehend information to all control room personnel.

An NRC control room design review audit (CRDR/A) was conducted from July 29 to July 31, 1981. Additional information to resolve PDA and CRDR/A issues was submitted to the NRC by SNUPPS letters dated August 12, 1981, January 19, 1982, March 16, 1982 and April 12, 1982. Additional information, addressing panels specific to WCGS, was submitted to the NRC by Operating Agent letters dated January 15, 1982, March 10, 1982 and June 29, 1982.

In response to Supplement 1 to NUREG-0737, additional detailed control room design review (DCRDR) information was provided to the NRC by SNUPPS letters:

April 15, 1983 - Response to Generic Letter 82-33

June 30, 1983 - DCRDR Program Plan

November 28, 1983 - Revised DCRDR Program Plan

November 30, 1983 - Responses to PDA Issues

February 2, 1984 - DCRDR Summary Report

March 21, 1984 - Auxiliary Shutdown Panel Issues

June 29, 1984 - Revision to DCRDR Summary Report

October 10, 1984 - Task Analysis Procedure

December 21, 1984 - Human Factors Review

The NRC conducted a second onsite audit in March 1984.

The Operating Agent also addressed the status of resolution of human engineering discrepancies (HEDs) in a letter to the NRC dated May 11, 1984.

As a result of the DCRDR activities, including Control Room Inventory and Supplemental Survey and Auxiliary Shutdown Panel review, several significant activities were undertaken. Some of the major efforts are identified below and were performed together with the resolution of hundreds of specific human engineering findings.

1. A standard list of abbreviations was adopted to provide a uniform nomenclature for plant operators. The standard abbreviations were used to update control room equipment labels, annunciator windows, Auxiliary Shutdown Panel labels and plant computer software.

2. Several system mimic displays were extensively revised, e.g., Chemical and Volume Control System, Component Cooling Water System and electrical systems.

3. The J-handles of many control switches used on control boards were engraved with indicating arrows. The engraved arrows were filled with white paint for easy identification of handle position.

4. Approximately fifty instrumentation/control devices were relocated with attendant panel rewiring. An additional reactor coolant system wide range pressure channel was incorporated into the plant design.

5. Extensive use of demarcation lines was employed to visually isolate indication and control groups for systems and components.

6. Several hundred displays were modified to add tolerance bands to provide plant operators with information regarding range and setpoints.

In Supplement 5, to the WCGS Safety Evaluation Report, the NRC evaluated the DCRDR activities up to that time (March 1985) and concluded that the DCRDR substantially meets the requirements of Supplement 1 to NUREG-0737 except in the area of System Function Review and Task Analysis (SFR&TA).

The Task Analysis procedure was revised by SNUPPS letter dated April 1, 1985. By SNUPPS letters dated April 26, 1985 and May 24, 1985, a final report entitled "Task Analysis and Verification of the SNUPPS Control Room" was submitted to the NRC. Additional NRC questions regarding the SFR&TA were addressed by Operating Agent letters dated November 4, 1985 and November 5, 1986. The NRC staff evaluation, documenting resolution of the SFR and TA issue, was issued by letter dated December 2, 1986.

18.1.16.3 Conclusions

Based on the DCRDR activities and NRC staff review results summarized above, the Operating Agent acceptably complies with the regulatory requirements for control room design review.

18.1.17 PLANT SAFETY PARAMETER DISPLAY SYSTEM (I.D.2)

18.1.17.1 NRC Guidance Per NUREG-0696

The purpose of the safety parameter display system (SPDS) is to assist control room personnel in evaluating the safety status of the plant. The SPDS is to provide a continuous indication of plant parameters or derived variables representative of the safety status of the plant. The primary function of the SPDS is to aid the operator in the rapid detection of abnormal operating conditions. The functional criteria for the SPDS presented in this section are applicable for use only in the control room.

It is recognized that, upon the detection of an abnormal plant status, it may be desirable to provide additional information to analyze and diagnose the cause of the abnormality, execute corrective actions, and monitor plant response as secondary SPDS functions.

As an operator aid, the SPDS serves to concentrate a minimum set of plant parameters from which the plant safety status can be assessed. The grouping of parameters is based on the function of enhancing the operator's capability to assess plant status in a timely manner without surveying the entire control room. However, the assessment based on SPDS is likely to be followed by confirmatory surveys of many non-SPDS control room indicators.

Human factors engineering shall be incorporated in the various aspects of the SPDS design to enhance the functional effectiveness of control room personnel. The design of the primary or principal display format shall be as simple as possible, consistent with the required function, and shall include pattern and coding techniques to assist the operator's memory recall for the detection and recognition of unsafe operating conditions. The human-factored concentration of these signals shall aid the operator in functionally comparing signals in the assessment of safety status.

All data for display shall be validated where practicable on a realtime basis as part of the display to control room personnel. For example, redundant sensor data may be compared, the range of a parameter may be compared to predetermined limits, or other quantitative methods may be used to compare values. When an unsuccessful validation of data occurs, the SPDS shall contain means of identifying the impacted parameter(s). Operating procedures and operator training in the use of the SPDS shall contain information and provide guidance for the resolution of unsuccessful data validation. The objective is to ensure that the SPDS presents the most current and accurate status of the plant possible and is not compromised by unidentified faulty processing or failed sensors.

The SPDS shall be in operation during normal and abnormal operating conditions. The SPDS shall be capable of displaying pertinent information during steady-state and transient conditions. The SPDS shall be capable of presenting the magnitudes and the trends of parameters or derived variables as necessary to allow rapid assessment of the current plant status by control room personnel.

The parameter trending display shall contain recent and current magnitudes of the parameter as a function of time. The derivation and presentation of parameter trending during upset conditions is a task that may be automated, thus freeing the operator to interpret the trends rather than generate them. Display of time derivatives of the parameters in lieu of trends to both optimize operator-process communication and conserve space may be acceptable.

The SPDS may be a source of information to other systems, and the functional criteria of these systems shall state the required interfaces with the SPDS. Any interface between the SPDS and a safety system shall be isolated in accordance with the safety system criteria to preserve channel independence and ensure the integrity of the safety system in the case of SPDS malfunction. Design provisions shall be included in the interfaces between the SPDS and nonsafety systems to ensure the integrity of the SPDS upon failure of nonsafety equipment.

A qualification program shall be established to demonstrate SPDS conformance to the functional criteria of this [NUREG-0696] document.

18.1.17.2 <u>The Operating Agent Response</u>

Supplement 1 to NUREG-0737 (Generic Letter 82-33, dated December 17, 1982) provided guidance and requirements for the SPDS which superceded previous NRC guidance.

In response to the NUREG-0696 design criteria guidance, a detailed description of the SPDS conceptual design was submitted to the NRC by SNUPPS letter dated June 1, 1981. In response to Generic Letter 82-33, further details were provided in a SNUPPS letter dated April 15, 1983. By SNUPPS letter dated January 13, 1984, an analysis of the bases for SPDS parameter selection was submitted to the NRC.

Based on the NRC review of the submitted information and the results of an NRC audit of the WCGS SPDS conducted in August 1984, the NRC staff concluded that the SNUPPS utilities were required to address (refer to WCGS Safety Evaluation Report, Supplement 5):

1. A commitment to add or justify not adding containment isolation status to the SPDS,

2. The inclusion of additional events in the SPDS variable validation and verification effort,

3. Involvement of human factors professionals in the design, and

4. Human engineering discrepancies identified during the NRC audit.

By SNUPPS letters dated September 5, 1984 and February 27, 1986, the above issues were addressed and the entire verification and validation program for the SPDS at the SNUPPS plants was reported to be successfully completed.

18.1.17.3 Conclusions

Based on the above summary of SPDS activities, the WCGS SPDS design agrees adequately with the requirements established in Supplement 1 to NUREG-0737.

18.1.18 SPECIAL LOW POWER TESTING AND TRAINING (I.G.1)

18.1.18.1 NRC Guidance Per NUREG-0694

NUREG-0694, "TMI-Related Requirements for New Operating Licenses," requires applicants for a new operating license to define and commit to a special low-power testing program approved by the NRC staff, to be conducted at power levels no greater than 5 percent, for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training. This requirement must be met before fuel loading.

Position

The staff position was stated in a letter to the applicants dated November 14, 1980. This letter stated that the program should provide for the following:

> "Each licensed reactor operator (RO or SRO who performs RO or SRO duties, respectively) should experience the initiation, maintenance, and recovery from natural circulation mode, using nuclear heat to simulate decay heat. Operators should be able to recognize when natural circulation has stabilized, and should be able to control saturation margin, RCS pressure, and heat removal rate without exceeding specified operating limits.
>
> These tests should demonstrate the following plant characteristics: length of time required to stabilize natural circulation, core flow distribution, ability to establish and maintain natural circulation with or without onsite and offsite power, and the ability to uniformly borate and cool down to hot shutdown conditions, using natural circulation. The latter demonstration may be performed using decay heat following power ascension and vendor acceptance tests, and need only be performed at those plants for which the tests has not been demonstrated at a comparable prototype plant."

18.1.18.2 The Operating Agent Response

The WCGS natural circulation testing requirements are based on post-Three Mile Island (TMI) regulatory positions and NRC Branch

Technical Position RSB 5-1. In response to the post-TMI positions, Westinghouse developed a special low-power test program which was approved by the NRC. In accordance with the test program, prototype natural circulation testing for 4-loop plants was performed at the Diablo Canyon plant. The prototype testing was performed in 1985 and acceptably demonstrated plant characteristics important to plant shutdown under natural circulation conditions, such as, length of time to achieve natural circulation, the ability to borate the reactor coolant system under natural circulation conditions and the ability to cool the plant down and depressurize under natural circulation conditions. The Diablo Canyon test results have been determined to be applicable to the WCGS design.

Plant-specific natural circulation testing was conducted at one SNUPPS plant (Callaway Plant -- operated by Union Electric Company). Sufficient data was collected during this testing to validate the simulation of natural circulation on the WCGS simulator. All licensed operators for WCGS received natural circulation training by either participating in the natural circulation testing or by simulating natural circulation on a validated simulator.

1. Training - Each licensed RO (RO or SRO who performs RO or SRO duties respectively) participates in the initiation, maintenance and recovery from the natural circulation mode during the plant test or on the simulator. Operators are able to recognize when natural circulation has stabilized and will be able to control saturation margin, RCS pressure, and heat removal rates without exceeding specified operating limits.

2. Testing - The prototype and Callaway Plant tests demonstrated the following plant characteristics: Length of time required to stabilize natural circulation, core flow distribution, ability to establish and maintain natural circulation with or without onsite and offsite power, the ability to uniformly borate and cooldown to hot shutdown conditions using natural circulation and the ability to control reactor coolant system subcooling margins. Thermocouple/Core Cooling Monitor (T/CCM) system performance was not specifically addressed in the natural circulation testing; however, the parameters used by the T/CCM system (see Section 18.2.13.2) for subcooling calculations were monitored and used to control the natural circulation cooldown. Therefore, the capability of the T/CCM system to function during natural circulation conditions is assured.

3. Procedure Validation - These tests or the simulation make maximum practical use of WCGS written plant procedures to validate the completeness and accuracy of the procedures.

18.1.18.3 Conclusion

The Operating Agent testing and training program meets Item I.G.1 of NUREG-0737.

Table 18.1-1

(Sheet 1 of 2)

ISEG FUNCTION CROSS REFERENCE

ISEG Function	Implementing Procedures
Examining plant operating characteristics, NRC issuances, industry advisories, reportable events, and other sources of plant design and operating experience information, including plants of similar design, which may indicate areas of plant safety.	AP 20E-001, “Industry Operating Experience Program” AP 23-006, “System Engineering Program” AP 28A-100, “Condition Reports” AI 17C-006, “Results Engineering Program”
Through the corrective action program, maintenance rule program and the self assessment program, detailed recommendations are made to the Vice President Engineering for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving plant safety.	AP 23-006, “System Engineering Program” AP 23M-001, “WCGS Maintenance Rule Program” AP 28A-100, “Condition Reports” AP 28D-001, “Self Assessment Process”
Maintaining surveillance of plant activities to provide independent verification that these activities are performed correctly and that human errors are reduced as much as practical.	AP 28A-100, “Condition Reports” AI 17C-006, “Results Engineering Program” AP 23M-001, “WCGS Maintenance Rule Program” AP 28D-001, “Self Assessment Process”
Independent review of plant activities and operating experience information.	AP 20E-001, “Industry Operating Experience Program” AP 23-006, “System Engineering Program” AI 17C-006, “Results Engineering Program”
Perform independent technical evaluations of plant maintenance, modifications, operational problems, operational analysis activities	AP 23-006, “System Engineering Program” AP 23M-001, “WCGS Maintenance Rule Program” AP 28A-100, “Condition Reports” AI 17C-006, “Results Engineering Program” AP 05-002, “Dispositions and Change Packages”

Table 18.1-1

(Sheet 2 of 2)

ISEG FUNCTION CROSS REFERENCE

ISEG Function	Implementing Procedures
Develop appropriate detailed recommendations for revisions to procedures or modifications to equipment as may be necessary.	AP 23M-001, "WCGS Maintenance Rule Program" AP 28A-100, "Condition Reports" AI 17C-006, "Results Engineering Program"
Survey plant maintenance operations and test activities to provide verification independent of the plant in accordance with established procedures.	AP 23-006, "System Engineering Program" AP 23M-001, "WCGS Maintenance Rule Program" AI 17C-006, "Results Engineering Program"

18.2 SITING AND DESIGN

18.2.1 POSTACCIDENT REACTOR COOLANT SYSTEM VENTING (II.B.1)

18.2.1.1 NRC Guidance Per NUREG-0737

Position

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensible gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the vents shall conform to the requirements of Appendix A to 10 CFR Part 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that ensures a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

1. Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10 CFR 50.46.

2. Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

Clarification

A. General

   1. The important safety function enhanced by this venting capability is core cooling. For events beyond the present design basis, this venting capability will substantially increase the plant's ability to deal with large quantities of noncondensible gas which could interfere with core cooling.

2. Procedures addressing the use of the reactor coolant system vents should define the conditions under which the vents should be used as well as the conditions under which the vents should not be used. The procedures should be directed toward achieving a substantial increase in the plant being able to maintain core cooling without loss of containment integrity for events beyond the design basis. The use of vents for accidents within the normal design basis must not result in a violation of the requirements of 10CFR50.44 or 10CFR50.46.

3. The size of the reactor coolant vents is not a critical issue. The desired venting capability can be achieved with vents in a fairly broad spectrum of sizes. The criteria for sizing a vent can be developed in several ways. One approach, which may be considered, is to specify a volume of noncondensible gas to be vented and in a specific venting time. For containments particularly vulnerable to failure from large hydrogen releases over a short period of time, the necessity and desirability for contained venting outside the containment must be considered (e.g., into a decay gas collection and storage system).

4. Where practical, the reactor coolant system vents should be kept smaller than the size corresponding to the definition of LOCA (10 CFR 50, Appendix A). This will minimize the challenges to the emergency core cooling system (ECCS) since the inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation, although it may result in leakage beyond technical specification limits. On PWRs, the use of new or existing lines whose smallest orifice is larger than the LOCA definition will require a valve in series with a vent valve that can be closed from the control room to terminate the LOCA that would result if an open vent valve could not be reclosed.

5. A positive indication of valve position should be provided in the control room.

6. The reactor coolant vent system shall be operable from the control room.

7. Since the reactor coolant system vent will be part of the reactor coolant system pressure boundary,

all requirements for the reactor pressure boundary must be met, and, in addition, sufficient redundancy should be incorporated into the design to minimize the probability of an inadvertent actuation of the system. Administrative procedures may be a viable option to meet the single-failure criterion. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 10CFR50.46.

8. The probability of a vent path failing to close, once opened, should be minimized; this is a new requirement. Each vent must have its power supplied from an emergency bus. A single failure within the power and control aspects of the reactor coolant vent system should not prevent isolation of the entire vent system, when required. On BWRs, block valves are not required in lines with safety valves that are used for venting.

9. Vent paths from the primary system to within containment should go to those areas that provide good mixing with containment air.

10. The reactor coolant vent system (i.e., vent valves, block valves, position indication devices, cable terminations, and piping) shall be seismically and environmentally qualified in accordance with IEEE 344-1975 as supplemented by Regulatory Guide 1.100, 1.92 and SEP 3.92, 3.43, and 3.10. Environmental qualifications are in accordance with the May 23, 1980 Commission Order and Memorandum (CLI-80-21).

11. Provisions to test for operability of the reactor coolant vent system should be a part of the design. Testing should be performed in accordance with the ASME Code.

12. It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factor analysis should be performed taking into consideration:

    a. The use of this information by an operator during both normal and abnormal plant conditions.

b. Integration into emergency procedures.

c. Integration into operator training.

d. Other alarms during emergency and need for prioritization of alarms.

B. PWR Vent Design Considerations

1. Each PWR licensee should provide the capability to vent the reactor vessel head. The reactor vessel head vent should be capable of venting noncondensible gas from the reactor vessel hot legs (to the elevation of the top of the outlet nozzle) and cold legs (through head jets and other leakage paths).

2. Additional venting capability is required for those portions of each hot leg that cannot be vented through the reactor vessel head vent or pressurizer. It is impractical to vent each of the many thousands of tubes in a U-tube steam generator; however, the staff believes that a procedure can be developed that ensures that sufficient liquid or steam can enter the U-tube region so that decay heat can be effectively removed from the RCS. Such operating procedures should incorporate this consideration.

3. Venting of the pressurizer is required to ensure its availability for system pressure and volume control. These are important considerations, especially during natural circulation.

18.2.1.2 The Operating Agent Response

The WCGS design provides the capability of venting the RCS to ensure that, if noncondensible gases become present in the RCS, regardless of the means postulated for generation of such noncondensibles, gases can be vented from the system, thereby ensuring that the flow paths associated with natural circulation core cooling capability are maintained. The venting capability is provided by the existing redundant pressurizer power-operated relief valves (PORVs) and their associated motor-operated isolation valves which can be used for the venting of the pressurizer and by the reactor vessel head vent system which provides redundant venting capability of the reactor vessel, RCS hot leg piping, and RCS cold leg piping via bypass leakage paths to the vessel head. The design features of these systems are discussed below.

The capability for venting of the pressurizer and the reactor vessel head is provided via safety grade, Class IE, environmentally qualified, seismic Category I, redundant systems, which meet the single failure criteria assuring both vent opening and vent closing capabilities. Block valves are an integral part of both the pressurizer and reactor vessel head vent system and meet the same qualification requirements as the vent valves.

The size of the RCS vents is determined as follows:

1. The pressurizer vent was based on the existing PORV (3-inch valve) capabilities.

2. The reactor vessel head vent system incorporates a 3/8-inch orifice to limit the maximum reactor coolant flow rate to a value less than that which defines a LOCA (see Figure 18.2-1).

The design provides for a motor-operated isolation valve in series with each pressurizer PORV. These PORV isolation valves may be either remotely actuated from the control room or automatically closed based on an RCS pressure setpoint. The setpoint is selected based on providing isolation prior to actuation of the safety injection system. Control room indication is provided for the pressurizer PORVs and PORV isolation valves and for the reactor vessel head vent valves. Each vent is remotely operable from the control room. An individual handswitch is provided for each valve.

The design of the RCS venting systems minimizes the probability of an inadvertent opening and consequence of such an opening.

1. The pressurizer vent system:

   The pressurizer PORVs are normally closed, Class IE solenoid valves that energize to open. Thus, loss of power will not actuate these valves. The PORV isolation valves are normally open, motor-operated valves. As discussed above, assuming an inadvertent opening of the PORV or its failure to close, a protection grade Class IE signal is provided to automatically close the associated block valve.

2. The reactor vessel head vent system:

   Each of the redundant vent paths off of the reactor vessel head contains two in-series, normally closed, same safety train, Class IE, environmentally qualified solenoid valves. The two normally closed valves in series limit any postulated events which could result in an inadvertent opening of the vent.

The pressurizer vents to the pressurizer relief tank. The reactor vessel head vent system valves are located on the CRDM seismic support platform above the reactor vessel. The discharge from these valves is directed to the open area of the containment above the refueling pool. This area precludes the potential for forming stagnant pockets of vented gases. Mixing and cooling of the vented gases is accomplished using permanent plant systems.

The Westinghouse Owners Group (WOG) has developed a generic reactor vessel head vent guideline. The Operating Agent has considered the generic guidance developed by the WOG in the development of procedures for use of the head vent system.

18.2.1.3 Conclusion

The WCGS design for the postaccident reactor coolant system vent system meets the applicable requirements of item II.B.1 of NUREG-0737.

18.2.2 DESIGN REVIEW OF THE PLANT SHIELDING (II.B.2)

18.2.2.1 NRC Guidance Per NUREG-0737

Position

With the assumption of a postaccident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 (i.e., the equivalent of 50 percent of the core radioiodine, 100 percent of the core noble gas inventory, and 1 percent of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding-design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during postaccident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or postaccident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

Clarification

The purpose of this item is to ensure that licensees examine their plants to determine what actions can be taken over the short-term to reduce radiation levels and increase the capability of operators to control and mitigate the consequences of an accident. These actions should be taken pending conclusions resulting in the long-term degraded core rulemaking, which may result in a need to consider additional sources.

Any area which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident is designated as a vital area. For the purposes of this evaluation, vital areas and equipment are not necessarily the same vital areas or equipment defined in 10 CFR 73.2 for security purposes. The security center is listed as an area to be considered as potentially vital, since access to this area may be necessary to take action to give access to other areas in the plant.

The control room, technical support center (TSC), sampling station, and sample analysis area must be included among those areas where access is considered vital after an accident. (See Item III.A.1.2 for discussion of the TSC and emergency operations facility.) The evaluation to determine the necessary vital areas should also include, but not be limited to, consideration of the post-LOCA hydrogen control system, containment isolation reset control area, manual ECCS alignment area (if any), motor control centers, instrument panels, emergency power supplies, security center, and radwaste control panels. Dose rate determinations need not be for these areas if they are determined not to be vital.

As a minimum, necessary modifications must be sufficient to provide for vital system operation and for occupancy of the control room, TSC, sampling station, and sample analysis area.

In order to ensure that personnel can perform the necessary postaccident operations in the vital areas, the following guidance is to be used by licensees to evaluate the adequacy of radiation protection to the operators:

1. Source Term

   The minimum radioactive source term should be equivalent to the source terms recommended in Regulatory Guides 1.3, 1.4, and 1.7 and Standard Review Plan 15.6.5 with appropriate decay times based on plant design (i.e., you may assume that the radioactive decay that occurs before fission products can be transported to various systems).

a. Liquid-Containing Systems: 100 percent of the core equilibrium noble gas inventory, 50 percent of the core equilibrium halogen inventory, and 1 percent of all others are assumed to be mixed in the reactor coolant and liquids recirculated by residual heat removal (RHR), high-pressure coolant injection (HPCI), and low-pressure coolant injection (LPCI), or the equivalent of these systems. In determining the source term for recirculated, depressurized cooling water, you may assume that the water contains no noble gases.

b. Gas-Containing Systems: 100 percent of the core equilibrium noble gas inventory and 25 percent of the core equilibrium halogen activity are assumed to be mixed in the containment atmosphere. For vapor-containing lines connected to the primary system (e.g., BWR steam lines), the concentration of radioactivity shall be determined, assuming that the activity is contained in the vapor space in the primary coolant system.

2. Systems Containing the Source

Systems assumed in your analysis to contain high levels of radioactivity in a postaccident situation should include, but not be limited to, containment, residual heat removal system, safety injection systems, chemical and volume control system (CVCS), containment spray recirculation system, sample lines, gaseous radwaste systems, and standby gas treatment systems (or equivalent of these systems). If any of these systems or others that could contain high levels of radioactivity were excluded, you should explain why such systems were excluded. Radiation from the leakage of systems located outside of the containment need not be considered for this analysis. Leakage measurement and reduction is treated under Item III.D.1.1, "Integrity of Systems Outside Containment Likely To Contain Radioactive Material for PWRs and BWRs." Liquid waste systems need not be included in this analysis. Modifications to liquid waste systems will be considered after completion of Item III.D.1.4, "Radwaste System Design Features To Aid in Accident Recovery and Decontamination."

3. Dose Rate Criteria

The design dose rate for personnel in a vital area should be such that the guidelines of GDC 19 will not be exceeded during the course of the accident. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel should not be in excess of 5 rem whole body, or its equivalent to any part of the body for the duration of the accident. When determining the dose to an operator, care must be taken to determine the necessary occupancy times in a specific area. For example, areas requiring continuous occupancy will require much lower dose rates than areas where minimal occupancy is required. Therefore, allowable dose rates will be based upon expected occupancy, as well as the radioactive source terms and shielding. However, in order to provide a general design objective, we are providing the following dose rate criteria with alternatives to be documented on a case-by-case bases. The recommended dose rates are average rates in the area. Local hot spots may exceed the dose rate guidelines. These doses are design objectives and are not to be used to limit access in the event of an accident.

a. Areas Requiring Continuous Occupancy: <15 mrem/hr (averaged over 30 days). These areas will require full-time occupancy during the course of the accident. The control room and onsite technical support center are areas where continuous occupancy will be required. The dose rate for these areas is based on the control room occupancy factors contained in SRP 6.4.

b. Areas Requiring Infrequent Access: GDC 19. These areas may require access on an irregular basis, not continuous occupancy. Shielding should be provided to allow access at a frequency and duration estimated by the licensee. The plant radiochemical/ chemical analysis laboratory, radwaste panel, motor control center, instrumentation locations, and reactor coolant and containment gas sample stations are examples of sites where occupancy may be needed often, but not continuously.

4. Radiation Qualification of Safety-Related Equipment

The review of safety-related equipment which may be unduly degraded by radiation during postaccident operation of this equipment relates to equipment inside and outside of the primary containment. Radiation source terms calculated to determine environmental qualification of safety-related equipment consider the following:

a. LOCA events which completely depressurize the primary system should consider releases of the source term (100 percent noble gases, 50 percent iodines, and 1 percent particulates) to the containment atmosphere.

b. LOCA events in which the primary system may not depressurize should consider the source term (100 percent noble gases, 50 percent iodines, and 1 percent particulate) to remain in the primary coolant. This method is used to determine the qualification doses for equipment in close proximity to recirculating fluid systems inside and outside of the containment. Non-LOCA events both inside and outside of the containment should use 10 percent noble gases, 10 percent iodines, and 0 percent particulate as a source term.

The following table summarizes these considerations:

Containment	LOCA Source Term (Noble Gas/Iodine/ Particulate)	Non-LOCA High-Energy Line Break Source Term(Noble Gas/Iodine/ Particulate)
	%	%
Outside	(100/50/1) in RCS	(10/10/0) in RCS
Inside	Larger of (100/50/1) in containment or (100/50/1) in RCS	(10/10/0) in RCS

18.2.2.2 The Operating Agent Response

The shielding design criteria used for WCGS is in accordance with NRC Standard Review Plan 12.2 and is described in Section 12.3.2 of the USAR. Two basic plant conditions are the bases of the shielding design, normal full power operation, and plant shutdown. The shielding design objectives for these conditions and anticipated operational occurrences, as stated in Section 12.3.2.1, are:

a. To ensure that radiation exposure to plant operating personnel, contractors, administrators, visitors, and proximate site boundary occupants are ALARA and within the limits of 10 CFR 20.

b. To ensure sufficient personnel access and occupancy time to allow normal anticipated maintenance, inspection, and safety-related operations required for each plant equipment and instrumentation area.

c. To reduce potential equipment neutron activation and mitigate the possibility of radiation damage to materials.

d. The control room is sufficiently shielded, so that the direct dose plus the inhalation dose (calculated in Chapter 15.0) will not exceed the limits of GDC-19.

Radiation zones have been established, based on required personnel access during these plant conditions.

18.2.2.2.1 Design Review of Plant Shielding

18.2.2.2.1.1 General

The following discussion provides a description of the design review of plant shielding of spaces around systems that may contain highly radioactive materials as a result of an accident. Systems required to process reactor coolant outside the containment during post-accident conditions were selected for evaluation.

The radiation and shielding design review was performed to identify the location of vital areas and equipment such as the control room, sample station, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during post-accident operations of these systems. Additionally, the review results ensure that adequate access to vital areas and protection of safety-related equipment are provided.

As shown in Figures 18.2-2 through 18.2-11, a number of radiation zone maps and associated dose rate decay curves have been produced as a result of the design review. Radiation levels for various areas around contaminated systems for various times can be found on these maps and curves. Operators may refer to the maps and curves to apprise themselves of the locations of potentially high radiation areas for any time following the postulated accident. These maps and curves are available in the critical post-accident control and support areas, e.g., control room, TSC, etc., for use following postulated DBA's.

18.2.2.2.1.2 Scope of Design Review

18.2.2.2.1.2.1 Systems Engineering Methodology

A. Selection of Systems for Shielding Review

Plant systems considered in the shielding review are classified into the following categories:

Category A (Recirculation Systems)

The first category of systems are those systems designed to mitigate a design basis loss of coolant accident and which might contain highly radioactive sources. Such systems include the emergency core cooling systems.

For the shielding review, the ECCS systems were postulated to contain significant additional sources of radioactivity in excess of the original plant design basis.

The following systems were selected to ensure the radiation safety concern is adequately addressed by the existing plant shielding design:

1. Those portions of the containment spray systems used to recirculate water from the containment sump back into the containment.

2. Those portions of the residual heat removal systems used to recirculate water from the containment sump back into the containment.

3. Those portions of the safety injection system used to recirculate water from the containment sump back into the containment.

4. Those portions of the Chemical and Volume Control System (CVCS) used to recirculate water from the containment sump back into the containment.

Category B (Extensions of Containment Atmosphere)

The second category of systems are the systems or portions of systems which would contain radioactivity by virtue of their connection to the containment atmosphere following an accident. These systems would not be expected to contain a significant level of radioactive sources that are considered in this shielding review, since proper operation of the emergency core cooling systems is expected to prevent extensive core damage. Nevertheless, such sources have been postulated for those portions of the post-accident containment hydrogen analyzer system external to the containment which would contain the atmosphere from the containment. An evaluation was also completed for a post-accident recovery sample should it be needed. (Amendment 137)

Category C (Liquid Samples)

The third category of systems is sampling systems. As discussed in Section 18.2.3, NUREG-0737, Task II.B.3 requires that certain post-accident liquid samples be obtained from the reactor coolant system or containment systems. Samples are no longer needed under this requirement. Those portions of the sampling system which must be used have been evaluated to assure that steps can be taken to obtain a post-accident recovery sample should it be needed. (Amendment 137)

B. Radioactive Source Release Fractions

Per NUREG-0737, the following release fractions were used as a basis for determining the concentrations for the shielding review:

1. Source A: Containment atmosphere - 100 percent noble gases, 25 percent halogens

2. Source B: Reactor coolant - 100 percent noble gases, 50 percent halogens, 1 percent solids

3. Source C: Containment sump liquid - 50 percent halogens, 1 percent solids

These release fractions were applied to the total curies available for the particular chemical species (i.e., noble gas, halogens, or solid) for an equilibrium fission product inventory for the WCGS core.

The release fraction for Cs was assumed to be 1 percent for the purposes of this shielding review. However, a relationship was developed which related the dose rates calculated, assuming 1 percent Cs, to the dose rate that would be expected if 50 percent of the Cs was released to the liquid source (as recommended by Revision 1 to Regulatory Guide 1.89, "Qualification of Class IE Equipment for Nuclear Power Plants"). This relationship is provided in Figure 18.2-11. No noble gases were included in the containment sump liquid (Source C) because Regulatory Guide 1.7 has set this precedent in modeling liquids in the containment sump.

C. Source Term Models

The preceding section (B) outlines the assumptions used for release fractions for the shielding design review. However, these release fractions are only the first step in modeling the source terms for the activity concentrations in the systems under review. The important modeling parameters, decay time and dilution volume, obviously also affect any shielding analysis. The following sections outline the rationale for the selection of values for these key parameters.

1. Decay Time

For the first stage of the shielding design review process, no decay time credit was used with the above releases. The primary reason for this was to develop a set of normalized accident radiation zone maps (i.e., no decay) that could be used as a tool by the plant staff along with a set of decay curves to quantitatively assess the plant status quickly following any abnormal occurrence. Decay curves are provided for the containment atmosphere and containment sump liquid only. Except for areas adjacent to the containment, the sump liquid source will be the dominating contributor.

2. Dilution Volume

The volume used for dilution is important, since it affects the calculations of dose rate in a linear fashion. The following dilution volumes were used with the release fractions and decay times listed above to arrive at the actual source terms used in the shielding reviews:

a. Source A: Containment free volume.

b. Source B: Reactor coolant system volume.

c. Source C: The volume of water present at the time of recirculation (reactor coolant system + refueling water storage tank + accumulator tanks).

3. Associated Sources and Systems

For the following systems, the source considered is listed. Note that normally shut valves were assumed to remain shut.

a. Containment spray system - At the initiation of recirculation, Source C was used.

b. Safety injection system - At the initiation of recirculation, Source C was used.

c. Residual heat removal system - Source C was used for sump recirculation mode.

d. Sampling system - The sources used in the shielding design review for sampling systems were as follows:

Containment air sample - Source A
Reactor coolant sample - Source B
Containment sump sample - Source C

e. CVCS system - The liquid source was Source C.

18.2.2.2.1.2.2 Shielding Design Review Methodology

A. Analytical Shielding Techniques

The previous sections outlined the rationale and assumptions used for the selection of the systems in the shielding design review, as well as the formulation of the sources for those systems. The next step in the review process was to use those sources to estimate dose rates from those selected systems. The dose rates were determined using a point-kernel computer code developed by Bechtel. This code utilizes the semi-empirical methods developed by Rockwell (Reference 8) for calculating the direct gamma dose rates. To determine the dose rate contribution from the containment, QAD-CG (Reference 9) was used. For corridors outside compartments, reviews were done to check the dose rate transmitted into the corridor through the walls of adjacent compartments. Checks were also made for any piping or equipment that could directly contribute to corridor dose rates, i.e., piping that may be running directly in the corridor or equipment/piping in a compartment that could shine directly into corridors with no attenuation through compartment walls.

B. Accident Radiation Zone Maps

Radiation levels are evaluated using the radiation zone maps, Figures 18.2-2 through 18.2-9, and associated decay curves, Figures 18.2-10 and 18.2-11, and are considered in parallel with required operator actions.

The zone boundaries were formulated based on the following rationale:

Zone Designation	Rationale	$\dot{D}$, Zone Dose Rate Limits (Rem/hr)
A-I	The first zone is consistent with the personnel radiation exposure guidelines of Task II.B.2 of NUREG-0737 for vital areas.	$0 \leq \dot{D} \leq 0.015$
A-II	The second zone is consistent with the personnel radiation exposure guidelines of Task II.B.2 of NUREG-0737 for vital areas requiring infrequent access or corridors to these areas. Such zones involve no time and motion evaluations.	$0.015 \leq \dot{D} \leq 0.100$
A-III	The third zone is consistent with the personnel radiation exposure guidelines of Task II.B.2 of NUREG-0737. Zones in this range required that a time and motion study be done to ensure that integrated exposure was not greater than 5 Rem as given in General Design Criteria 19.	$0.100 < \dot{D} \leq 5$

Zone Designation	Rationale	$\dot{D}$, Zone Dose Rate Limits (Rem/hr)
A-IV		$5 < \dot{D} \leq 50$
A-V		$50 < \dot{D} \leq 500$
A-VI		$500 < \dot{D} \leq 5000$
A-VII		$5000 < \dot{D} \leq 50,000$
A-VIII		$50,000 < \dot{D} \leq 500,000$

18.2.2.2.1.2.3 Personnel Exposure Limits and Methodology

A. Access

Operator actions that are required post-LOCA were reviewed to ensure that first priority safety actions can be achieved in the postulated radiation fields. This review ensures that access is available and required operator actions can be achieved as discussed in Section 18.2.2.2.1.3.

B. Personnel Radiation Exposure Guidelines

The general basis for personnel radiation exposure guidelines was 10 CFR 50, Appendix A, GDC 19. The following additional radiation limit guidelines were used to evaluate occupancy and accessibility of plant vital areas. General area dose rates were used rather than maximum surface dose rates. Contributions from all sources were considered.

1. Vital areas requiring continuous occupancy

Vital areas such as control room, counting room, laboratory, and the onsite technical support center were verified to ensure the direct dose rate was less than 15 mr/hr. The 30 day average direct radiation dose rate is less than 15 mr/hr for the SAS room and the control room toilet.

2. Vital areas requiring infrequent access or corridors to these vital areas

   For these areas, the dose rate was verified to be less than 5 R/hr except as noted in Section 18.2.2.2.1.3.

18.2.2.2.1.3 Results of Review

The shielding design criteria and objectives have been met in the design of WCGS. These criteria and objectives have been extended to the areas designated to be the onsite Technical Support Center and the Operations Support Center, as required by the expected occupancy of these areas. The following is a discussion of the impact of a postulated LOCA or TMI-2 type event on the WCGS shielding design and is based on the WCGS specific system design capabilities:

A. LOCA

   Assuming a DBA LOCA with radiation source terms consistent with Regulatory Guides 1.4 and 1.7, plus the Cs fraction discussed in Section 18.2.2.2.1.2.1, all safety-related equipment and instrumentation will be qualified for the maximum equipment doses associated with the time that the equipment must function. All safety-related systems operations are performed either automatically or remote manually from the control room. Operations within the auxiliary building are not expected following a LOCA. During the long-term recovery phase, access to sample stations in the auxiliary building may be limited. Should a sample be requested, conditions will determine what steps will be taken to assure dose is ALARA. Due to Amendment 137, PASS is no longer used. As discussed above, the dose limitations of GDC-19 for control room operators are met.

B. TMI-2

   WCGS is designed to preclude events similar to the TMI-2 event. For example, the WCGS design includes reactor coolant system high point vents (as discussed in Section 18.2.1) and the associated Class IE instrumentation required to detect inadequate core cooling and thus precludes the degradation of the fuel cladding and any massive release of activity to the coolant. However, assuming that a TMI-2 event does occur, contamination of the auxiliary building is precluded by design: 1) Compliance with containment isolation criteria is described in Section 6.2.4 and Section 18.2.11 and precludes contamination of the auxiliary building by auxiliary systems, and 2) the WCGS design includes a dedicated, safety-related letdown system located totally within the containment which provides controlled letdown capability to the pressurizer relief tank, eliminating any operational need to contaminate the chemical and volume control system in the auxiliary building.

Based on the above, dose rates were not evaluated in the auxiliary building for an undiluted reactor coolant system source term being present in the residual heat removal system. Dose rates inside containment due to the TMI-2 type event have been considered for equipment qualification. Habitability of the TSC is addressed elsewhere in the USAR.

18.2.2.3 Conclusion

The shielding design criteria and objectives for WCGS meets the applicable recommendations of item II.B.2 of NUREG-0737 and Amendment 137. Radiation qualification of WCGS safety-related equipment is addressed in Section 3.11(B).

18.2.3 POSTACCIDENT SAMPLING SYSTEM (II.B.3)

18.2.3.1 NRC Guidance Per NUREG-0737

Position

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18-3/4 Rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses, assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

Clarification

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13 and October 30, 1979 clarification letters. The system provides both online isotopic analysis and chemical analysis with systems designed to operate in the accident environment. Provisions have also been included for taking undiluted and diluted grab samples. Accuracies of the online chemical analyzers will be comparable to those available from commercial grade analyzers.

1. The licensee shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.

2. The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hour time frame established above, quantification of the following:

    a. Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and non-volatile isotopes).

    b. Hydrogen levels in the containment atmosphere.

    c. Dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.

d. Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

3. Reactor coolant and containment atmosphere sampling during postaccident conditions shall not require an isolated auxiliary system [e.g., the letdown system, reactor water cleanup system (RWCUS)] to be placed in operation in order to use the sampling system.

4. Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or H2 gas in reactor coolant samples is considered adequate. Measuring the O2 concentration is recommended, but is not mandatory.

5. The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions, the licensee shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

6. The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of GDC 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). [Note that the design and operational review criterion was changed from the operational limits of 10 CFR Part 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979 letter from H. R. Denton to all licensees).

7. The analysis of primary coolant samples for boron is required for PWRs. (Note that Revision 2 of Regulatory Guide 1.97, when issued, will likely specify the need for primary coolant boron analysis capability at BWR plants.)

8. If inline monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples.

Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

9. The licensee's radiological and chemical sample analysis capability shall include provisions to:

   a. Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guide 1.3 or 1.4 and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 mCi/g to 10 Ci/g.

   b. Restrict background levels of radiation in the radiological and chemical analysis facility from sources, such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

10. Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe the radiological and chemical status of the reactor coolant systems.

11. In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:

   a. Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The post-accident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

b. The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high-efficiency particulate air (HEPA) filters.

c. Guidelines for analytical or instrumentation range are given below in Table II.B.3-1.

18.2.3.2 The Operating Agent Response

By Amendment 137 the in-line analyzers contained with PASS are no longer used. During a long term recovery, conditions will determine what steps will be taken to obtain a grab sample from the Nuclear Sample Panel SJ-143. Analyses will be done on site by appropriate instruments or shipped off-site as needed. The sample for the containment atmosphere is done using the sample flask on the containment hydrogen monitor as described in Section 6.2.5.2.2.3 and shown on Figure 6.2.5-1.

Guidelines of Table II.B.3-1 no longer apply.

TABLE II.B.3-1

ANALYSES FOR THE POSTACCIDENT SAMPLING SYSTEM

Liquids	Ranges
Radioisotopic identification	10^{-3} - 10^{7} μCi/cc
Boron	0 - 6,000 ppm
pH	1 - 13
Hydrogen	(Not required or performed. Reference USQD 59 98-0071, letter WO 98-0047 and letter 98-01418.)
Oxygen	0 - 20 ppm
Chloride	0 - 20 ppm
Conductivity	0.1 - 1,000 μ mhos

Gases	Ranges
Radioisotopic identification	10^{-7} - 10^{5} Ci/cc
Oxygen	0 - 50 wt%
Hydrogen	0 - 10 Volume Percent

Since the sample panel is located in the auxiliary building, any leakage from the system is filtered through the charcoal adsorber and HEPA filters of the auxiliary building emergency exhaust system (see Section 9.4.3).

The nuclear sampling system P&ID (M-12SJ01, M-12SJ02, M-12SJ03) are listed in Table 1.7-2.

Accessibility of the auxiliary building to obtain a grab sample was addressed in Section 18.2.2.

Core Damage Assessment Methodology (CDAM) was developed and approved by the NRC. WCAP-14696, “Westinghouse Owners Group Core Damage Assessment Guidance,” was developed and submitted to the NRC for review. This Core Damage Assessment Guidance (CDAG) utilizes installed instrumentation, rather than PASS samples to classify core damage accidents. NRC issued an SER on September 2, 1999 to approve the WCAP-14696 methodology. Justification for elimination of PASS was submitted to the NRC in WCAP-14986-A, “Post Accident Sampling System Requirements: A Technical Basis,” October 26, 1998, as supplemented by letters dated April 28, 1999, April 10, 2000, and May 22, 2000.

18.2.3.3 Conclusion

The postaccident sampling system design for WCGS is not required to meet the recommendations of Item II.B.3 of NUREG-0737. A Core Damage Assessment Guidance (WCAP-14696) is implemented to provide evaluation and action during an accident. With implementation of WCAP-14696, WCAP-14986-A and evaluations demonstrated that PASS was no longer required. Should contingency sampling be required during recovery, assessments will address taking samples from the Nuclear Sample System and the Containment Hydrogen Monitoring Equipment. No PASS samples are required to be taken. (Reference USQD 59 98-0071, letter WO 98-0047 and letter 98-01418.)

18.2.4 TRAINING FOR MITIGATING CORE DAMAGE (II.B.4)

18.2.4.1 NRC Guidance Per NUREG-0737

Position

The staff requires that the applicants develop and implement a program to ensure that all operating personnel are trained in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged.

Clarification

Shift Technical Advisors and operating personnel from the plant manager through the operations chain to the licensed operators shall receive the training listed below.

The training program shall include the following topics:

a. Incore Instrumentation

   1. Use of fixed or movable incore detectors to determine the extent of core damage and geometry changes.

   2. Use of thermocouples in determining peak temperatures; methods for extended range readings; methods for direct readings at terminal junctions.

   3. Methods for calling up (printing) incore data from the plant computer.

b. Excore Nuclear Instrumentation (NIS)

   Use of NIS for determination of void formation; void location basis for NIS response as a function of core temperatures and density changes.

c. Vital Instrumentation

   1. Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual versus indicated level).

2. Alternative methods for measuring flows, pressures, levels, and temperatures.

   (a) Determination of pressurizer level if all level transmitters fail.

   (b) Determination of letdown flow with a clogged filter (low flow).

   (c) Determination of other reactor coolant system parameters if the primary method of measurement has failed.

d. Primary Chemistry

   1. Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leaktight systems.

   2. Expected isotopic breakdown for core damage; for clad damage.

   3. Corrosion effects of extended immersion in primary water; time to failure.

e. Radiation Monitoring

   1. Response of process and area monitors to severe damage; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (over ranged detector); expected accuracy of detectors at different locations; use of detectors to determine the extent of core damage.

   2. Methods of determining dose rate inside the containment from measurements taken outside the containment.

f. Gas Generation

   1. Methods of H_2 generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of noncondensibles.

   2. H_2 flammability and explosive limit, sources of 0_2 in containment or reactor coolant system.

Managers and technicians in the Instrumentation and Control (I&C), health physics, and chemistry departments shall receive training commensurate with their responsibilities.

18.2.4.2 The Operating Agent Response

The Operating Agent provided a course in Mitigating Core Damage for licensed operator candidates. The outline of this course is provided in Table 18.2-1. The course, in conjunction with other lectures in the reactor operator training program, covered a minimum of 80 hours of training in the control or mitigation of accidents in which the core is severely damaged. A Mitigating Core Damage course was given to all licensed operators and their supervisors up to and including the Plant Manager prior to fuel load.

The current Mitigating Core Damage course is discussed in Section 13.2.

Supervisors and technicians in the Instrumentation and Controls, Health Physics and Chemistry groups were given training, prior to fuel load, commensurate with their responsibilities during accidents which involve severe core damage.

18.2.4.3 Conclusion

The Operating Agent's training program for mitigating core damage satisfies NUREG-0737.

18.2.5 PERFORMANCE TESTING OF BOILING-WATER REACTOR AND PRESSURIZED-WATER REACTOR RELIEF AND SAFETY VALVES (II.D.1)

18.2.5.1 NRC Guidance Per NUREG-0737

Position

Pressurized-water reactor and boiling-water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

Clarification

Licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. Reactor coolant system relief and safety valve qualification shall include qualification of associated control circuitry, piping, and supports, as well as the valves themselves.

A. Performance Testing of Relief and Safety Valves--The following information must be provided in report form by October 1, 1981 for BWRs and July 1, 1982 for PWRs.

   1. Evidence supported by test of safety and relief valve functionability for expected operating and accident (non-ATWS) conditions must be provided to NRC. The testing should demonstrate that the valves will open and reclose under the expected flow conditions.

   2. Since it is not planned to test all valves on all plants, each licensee must submit to NRC a correlation of other evidence to substantiate that the valves tested in the EPRI (Electric Power Research Institute) or other generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions, as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must also be accounted for, if it is different from the generic test loop piping.

   3. Test data, including criteria for success and failure of valves tested, must be provided for NRC staff review and evaluation. These test data should include data that would permit plant-specific evaluation of discharge piping and supports that are not directly tested.

B. Qualification of PWR Block Valves--Although not specifically listed as a short-term lessons learned requirement in NUREG-0578, qualification of PWR block valves is required by the NRC Task Action Plan NUREG-0660 under task item II.D.1. It is the understanding of the NRC that testing of several commonly used block valve designs is already included in the generic EPRI PWR safety and relief valve testing program to be completed by July 1, 1981. By means of this letter, NRC is establishing July 1, 1982 as the date for verification of block valve functionability. By July 1, 1982, each PWR licensee, for plants so equipped, should provide evidence supported by test that the block or isolation valves between the pressurizer and each power-operated relief valve can be operated, closed, and opened for all fluid conditions expected under operating and accident conditions.

C. ATWS Testing--Although ATWS testing need not be completed by July 1, 1981, the test facility should be designed to accommodate ATWS conditions of approximately 3,200 to 3,500 (Service Level C pressure limit) psi and 700 F with sufficient capacity to enable testing of relief and safety valves of the size and type used on operating pressurized-water reactors.

18.2.5.2 The Operating Agent Response

The PORVs in the WCGS design are relied on to function to alleviate over-pressurization that possibly could occur during startup of the reactor, or during cold shutdown conditions, and they may be relied on to function during shut down of the reactor, assuming only safety-grade equipment is functioning. (These functions are described in Section 5.2 and Appendix 5.4(A).) The PORVs are not required to function to mitigate the consequences of any design basis accident.

The PORVs are also designed to limit high pressure during normal operation. The description of this control function is presented in Sections 5.2 and 7.6. As discussed below, operability of the PORVs will be demonstrated by prototypical testing and appropriate analyses.

The safety valves for the WCGS design are relied on to limit primary system pressure following anticipated operational transients. The design basis for the safety valves is presented in Section 5.2. The valves are required by ASME Boiler and Pressure Vessel Code to mitigate excessive pressure increases, regardless of their source. As discussed below, operability of the safety valves was demonstrated by prototypical testing and appropriate analyses.

The reactor coolant system is provided with two PORVs and three code safety valves. Each PORV also has an associated motor-operated block valve.

The PORVs for WCGS were manufactured by Garrett; the safety valves were manufactured by Crosby. These valves are included in the safety and relief valve testing program that has been developed by the Electric Power Research Institute (EPRI). A description of this program entitled "Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems," dated December 13, 1979, was submitted to the NRC on December 17, 1979 (letters from W. J. Cahill, Jr., Chairman of EPRI Safety and Analysis Task Force, to H. Denton and D. Eisenhut, NRC). A revision to this program was submitted to the NRC in July 1980. The NRC staff completed its review of this program and found it acceptable.

An interim report on these valve tests was submitted by the PWR utilities to the NRC in July 1981. A final report on these tests was submitted in SNUPPS letter dated October 20, 1982 and a final report on piping and supports was provided by SNUPPS letter dated January 7, 1983 (distributed as 82-002).

Preoperational testing of the PORVs included monitoring the dynamic response of the relief valve discharge piping during actuation of the PORVs. These in-plant dynamic tests were initiated with a water-solid inlet (loop seal) at the PORVs and a steam bubble maintained in the pressurizer.

Regarding verification of the block valve functionability, WCGS information on qualification of the block valves was provided by SNUPPS letter dated July 1, 1982.

Based on the NRC review of the submittals addressing safety valves, PORVs, PORV block valves and associated piping, the Operating Agent was requested to provide additional information. SNUPPS letters dated June 30, 1986 and September 26, 1986 provided responses to the NRC questions.

18.2.5.3 Conclusion

The plan to demonstrate the operability of the PORVs and safety valves at WCGS satisfies the guidance of item II.D.1 in NUREG-0737. The NRC review of this issue is continuing.

18.2.6 DIRECT INDICATION OF RELIEF AND SAFETY VALVE POSITION (II.D.3)

18.2.6.1 NRC Requirement Per NUREG-0737

Position

Reactor coolant system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve-position detection device or a reliable indication of flow in the discharge pipe.

Clarification

1. The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.

2. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

3. The valve position indication may be safety grade. If the position indication is not safety grade, a reliable single-channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis of an action.

4. The valve position indication should be seismically qualified, consistent with the component or system to which it is attached.

5. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with Commission Order, May 23, 1980 (CLI-20-81).

6. It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factor analysis should be performed taking into consideration:

   a. The use of this information by an operator during both normal and abnormal plant conditions.

   b. Integration into emergency procedures.

   c. Integration into operator training.

   d. Other alarms during emergency and need for prioritization of alarms.

18.2.6.2 The Operating Agent Response

Safety-grade position indication is provided for each safety valve and power-operated relief valve (PORV) that indicates when the valve is not in its fully closed position. The position indication is seismically and environmentally qualified. The position indication for each valve is displayed in the control room, and an alarm is provided if any of the PORVs or safety valves is not fully closed.

Other, nonsafety-related instrumentation is provided on the valve discharge piping and the pressurizer relief tank to provide an alternate means of assessing the status of the safety valves and PORVs (see Figure 5.1-1, Sheet 2).

18.2.6.3 Conclusion

The WCGS design satisfies the guidance of Item II.D.3 of NUREG-0737.

18.2.7 AUXILIARY FEEDWATER SYSTEM EVALUATION (II.E.1.1)

18.2.7.1 NRC Guidance Per NUREG-0737

Position

The office of Nuclear Reactor Regulation is requiring reevaluation of the auxiliary feedwater (AFW) systems for all PWR operating plant licensees and operating license applications. This action includes:

1. Perform a simplified AFW system reliability analysis that uses event-tree and fault-tree logic techniques to determine the potential for AFW system failure under various loss-of-main-feedwater-transient conditions. Particular emphasis is given to determining potential failures that could result from human errors, common causes, single-point vulnerabilities, and test and maintenance outages.

2. Perform a deterministic review of the AFW system using the acceptance criteria of Standard Review Plan Section 10.4.9 and associated Branch Technical Position ASB 10-1 as principal guidance.

3. Reevaluate the AFW system flowrate design bases and criteria.

Clarification

Operating License Applicants - Operating license applicants have been requested to respond to staff letters of March 10, 1980 (W and C-E) and April 24, 1980 (B&W). These responses will be reviewed during the normal review process for these applications.

18.2.7.2 The Operating Agent Response

A reliability analysis of the WCGS auxiliary feedwater system (AFS) was submitted to the NRC by SNUPPS letter dated June 8, 1981. A comparison of the design with Standard Review Plan 10.4.9 and Branch Technical Position ASB 10-1 is provided in Section 10.4.9. An evaluation of the auxiliary feedwater system flowrate design bases and criteria was submitted by SNUPPS letter dated June 3, 1981.

The NRC staff reviewed the SNUPPS AFS design capabilities against the recommendations of a March 10, 1980 NRC letter (D. Ross, NRC to All Pending W and C-E License Applicants) which corresponds to NUREG-0737, Item II.E.1.1. Based on this review, a confirmatory licensing issue was identified, regarding physically securing the condensate storage tank manual isolation valve. This issue was resolved prior to initial fuel load.

18.2.7.3 Conclusion

The WCGS design and analyses for the AFS meet the recommendations of Item II.E.1.1 of NUREG-0737.

18.2.8 AUXILIARY FEEDWATER SYSTEM AUTOMATIC INITIATION AND FLOW INDICATION (II.E.1.2)

18.2.8.1 NRC Guidance Per NUREG-0737

Position - Part 1: AFS Automatic Initiation

Consistent with satisfying the requirements of General Design Criterion 20 of Appendix A to 10 CFR Part 50 with respect to the timely initiation of the auxiliary feedwater system (AFS), the following requirements shall be implemented in the short term:

1. The design shall provide for the automatic initiation of the AFS.

2. The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of AFS function.

3. Testability of the initiation signals and circuits shall be a feature of the design.

4. The initiating signals and circuits shall be powered from the emergency buses.

5. Manual capability to initiate the AFS from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.

6. The ac motor-driven pumps and valves in the AFS shall be included in the automatic actuation (simultaneous and/or sequential) of the loads onto the emergency buses.

7. The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFS from the control room.

In the long term, the automatic initiation signals and circuits shall be upgraded in accordance with safety-grade requirements.

Clarification

The intent of this recommendation is to ensure a reliable automatic initiation system. This objective can be met by providing a system which meets all the requirements of IEEE Standard 279-1971.

Position - Part 2: AFS Flowrate Indication

Consistent with satisfying the requirements set forth in General Design Criterion 13 to provide the capability in the control room to ascertain the actual performance of the AFS when it is called to perform its intended function, the following requirements shall be implemented:

1. Safety-grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.

2. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.

Clarification

The intent of this recommendation is to ensure a reliable indication of AFS performance. This objective can be met by providing an overall indication system that meets the following appropriate design principles:

For Westinghouse and Combustion Engineering Plants

1. To satisfy these requirements, W and C-E plants must provide as a minimum one auxiliary feedwater flow rate indicator and one wide-range steam-generator level indicator for each steam generator or two flowrate indicators.

2. The flow indication system should be:

    a. Environmentally qualified

    b. Powered from highly reliable, battery-backed non-Class 1E power source

    c. Periodically testable

    d. Part of plant quality assurance program

    e. Capable of display on command

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factor analysis should be performed, taking into consideration:

1. The use of this information by an operator during both normal and abnormal plant conditions.

2. Integration into emergency procedures.

3. Integration into operator training.

4. Other alarms during emergency and need for prioritization of alarms.

18.2.8.2 <u>The Operating Agent Response</u>

Automatic initiation of the AFS meets the NRC recommendations, as described in Sections 10.4.9 and 7.3.6. The AFS flowrate indication meets the NRC recommendations, as described in Sections 10.4.9 and 7.5.

The NRC staff reviewed the SNUPPS AFS design capabilities against the recommendations of a March 10, 1980 NRC letter (D. Ross, NRC to All Pending W and C-E License Applicants) which corresponds to NUREG-0737, Item II.E.1.1. Based on this review a confirmatory licensing issue was identified, regarding physically securing the condensate storage tank manual isolation valve. This issue was resolved prior to initial fuel load.

18.2.8.3 Conclusion

The WCGS design and analyses for the AFS meet the recommendations of Item II.E.1.2 of NUREG-0737.

18.2.9 EMERGENCY POWER SUPPLY FOR PRESSURIZER HEATERS (II.E.3.1)

18.2.9.1 NRC Guidance Per NUREG-0737

Position

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10 CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

1. The pressurizer heater power supply design shall provide the capability to supply, from either the offsite power source or the emergency power source (when offsite power is not available), a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls shall be connected to the emergency buses in a manner that will provide redundant power supply capability.

2. Procedures and training shall be established to make the operator aware of when and how the required pressurizer heaters shall be connected to the emergency buses. If required, the procedures shall identify under what conditions selected emergency loads can be shed from the emergency power source to provide sufficient capacity for the connection of the pressurizer heaters.

3. The time required to accomplish the connection of the preselected pressurizer heater to the emergency buses shall be consistent with the timely initiation and maintenance of natural circulation conditions.

4. Pressurizer heater motive and control power interfaces with the emergency buses shall be accomplished through devices that have been qualified in accordance with safety-grade requirements.

Clarification

1. Redundant heater capacity must be provided, and each redundant heater or group of heaters should have access to only Class 1E division power supply.

2. The number of heaters required to have access to each emergency power source is that number required to maintain natural circulation in the hot standby condition.

3. The power sources need not necessarily have the capacity to provide power to the heaters concurrently with the loads required for loss-of-coolant accident.

4. Any changover of the heaters from normal offsite power to emergency onsite power is to be accomplished manually in the control room.

5. In establishing procedure to manually load the pressurizer heaters onto the emergency power sources, careful consideration must be given to:

   a. Which ESF loads may be appropriately shed for a given situation.

   b. Reset of the safety injection actuation signal to permit the operation of the heaters.

   c. Instrumentation and criteria for operator use to prevent overloading a diesel generator.

6. The Class 1E interfaces for main power and control power are to be protected by safety-grade circuit breakers (see also Regulatory Guide 1.75).

7. Being non-Class 1E loads, the pressurizer heaters must be automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal (see item 5.b. above).

18.2.9.2 <u>The Operating Agent Response</u>

The total rated capacity of the pressurizer heaters at 480 volts ac is 1800 Kw (Table 5.1-1). The pressurizer heaters are divided into three groups (see Figure 8.3-1). The rated capacity of each group is as follows:

Group A - 692 Kw
Group B - 692 Kw
Group C - 416 Kw

The group C heaters are used for proportional control during power operation.

Groups A and B are the backup heater groups; each of these two groups is powered from a Class lE power source. This power is interrupted by the load shedder/sequencer following a safety injection or emergency bus undervoltage signal.

The controls for each backup pressurizer heater group are provided from a non-Class 1E 125 Vdc power system. The normal power source is from a non-Class 1E 480 Vac through a battery charger. There is a 125 Vdc battery backup to the 480 Vac supply (see Figure 8.3-6). Each battery charger of the 125-Vdc system is supplied from a single separation group of the 4.16-kV onsite emergency distribution system. When the 480-Vac system is unavailable following a loss-of-offsite power, the dc-backed power supplies will supply the backup pressurizer heater controls. Similar to the breakers feeding the heater load centers, the circuit breakers supplying the 125-Vdc battery chargers are automatically tripped upon an SIS or emergency bus undervoltage signal. They may be reclosed from the control room when desired after reset of the breaker tripping signals.

For additional reliability, a cross-tie is provided between Separation Groups 5 and 6 of the non-Class 1E 125-Vdc system. This will permit operation of selected loads of both separation groups in the event of a failure of either battery charger.

All the breakers which function upon SIS and bus undervoltage are seismically qualified isolation devices.

Analysis shows that subcooling would be maintained in the reactor coolant system for up to 4 hours without heat input from the pressurizer heaters. Pressure control for the reactor coolant system, as discussed in Section 5.4(A), can be accomplished without pressurizer heaters. If pressurizer heaters were used for pressure control, analysis indicates that 150 kW is sufficient to maintain subcooling. Plant procedures have been provided for manually connecting (from the control room) pressurizer heaters to emergency power sources following a loss of offsite power.

18.2.9.3 Conclusion

The WCGS design satisfies the guidance of item I.E.3.1 of NUREG-0737.

18.2.10 DEDICATED HYDROGEN PENETRATIONS (II.E.4.1)

18.2.10.1 NRC Guidance Per NUREG-0737

Position

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single-failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

Clarification

1. An acceptable alternative to the dedicated penetration is a combined design that is single-failure proof for containment isolation purposes and single-failure proof for operation of the recombiner or purge system.

2. The dedicated penetration or the combined single-failure proof alternative shall be sized such that the flow requirements for the use of the recombiner or purge system are satisfied. The design shall be based on 10 CFR 50.44 requirements.

3. Components furnished to satisfy this requirement shall be safety grade.

4. Licensees that rely on purge systems as the primary means of controlling combustible gases following a loss-of-coolant accident should be aware of the positions taken in SECY-80-399, "Proposed Interim Amendments to 10 CFR Part 50 Related to Hydrogen Control and Certain Degraded Core Considerations." This proposed rule, published in the Federal Register on October 2, 1980, would require plants that do not have recombiners to

have the capacity to install external recombiners by January 1, 1982. (Installed internal recombiners are an acceptable alternative to the above.)

5. Containment atmosphere dilution (CAD) systems are considered to be purge systems for the purpose of implementing the requirements of this TMI Task Action item.

18.2.10.2 The Operating Agent Response

The postaccident H_2 control is accomplished by redundant hydrogen recombiners which are permanently installed inside the containment. Therefore, dedicated hydrogen control penetrations are not required, and this item is not applicable to WCGS.

As a backup to the safety-related hydrogen control system, a means of purging hydrogen from the containment is provided. Only the containment penetrations and the associated isolation valves are safety-related in the hydrogen purge system. These penetrations are not the subject of this item, since they do not serve external hydrogen recombiners. Since the hydrogen recombiners are actuated from the control room, the shielding and personnel exposure limitations associated with recombiner use and development of procedures for reduction of doses are not applicable to WCGS.

18.2.10.3 Conclusion

Item II.E.4.1 is not applicable to WCGS.

18.2.11 CONTAINMENT ISOLATION DEPENDABILITY (II.E.4.2)

18.2.11.1 NRC Guidance Per NUREG-0737

Position

1. Containment isolation system designs shall comply with the recommendations of Standard Review Plan Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

2. All plant personnel shall give careful consideration to the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the re-evaluation to the NRC.

3. All nonessential systems shall be automatically isolated by the containment isolation signal.

4. The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

5. The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

6. Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP 6.2.4, Item II.3.f during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days. (A copy of the Staff Interim Position [was to be] enclosed as Attachment 1 [to NUREG-0737].)

7. Containment purge and vent isolation valves must close on a high radiation signal.

Clarification

1. The reference to SRP 6.2.4 in position 1 is only to the diversity requirements set forth in that document.

2. For postaccident situations, each nonessential penetration (except instrument lines) is required to have two isolation barriers in series that meet the requirements of General Design Criteria 54, 55, 56, and 57, as clarified by Standard Review Plan, Section 6.2.4. Isolation must be performed automatically (i.e., no credit can be given for operator action). Manual valves must be sealed closed, as defined by Standard Review Plan, Section 6.2.4, to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration must receive the diverse isolation signals.

3. Revision 2 to Regulatory Guide 1.141 will contain guidance on the classification of essential versus nonessential systems and is due to be issued by June 1981. Requirements for operating plants to review their list of essential and nonessential systems will be issued in conjunction with this guide, including an appropriate time schedule for completion.

4. Administrative provisions to close all isolation valves manually before resetting the isolation signals is not an acceptable method of meeting position 4.

5. Ganged reopening of containment isolation valves is not acceptable. Reopening of isolation valves must be performed on a valve-by-valve basis, or on a line-by-line basis, provided that electrical independence and other single-failure criteria continue to be satisfied.

6. The containment pressure history during normal operation should be used as a basis for arriving at an appropriate minimum pressure setpoint for initiating containment isolation. The pressure setpoint selected should be far enough above the maximum observed (or expected) pressure inside containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or fluctuations due to the accuracy of the pressure sensor. A margin of 1 psi above the maximum expected containment pressure should be adequate to account for instrument error. Any proposed values greater than 1 psi will require detailed justification. Applicants for an operating license and operating plant licensees that have operated less than one year should use pressure history data from similar plants that have operated more than one year, if possible, to arrive at a minimum containment setpoint pressure.

7.) Sealed-closed purge isolation valves shall be under administrative control to ensure that they cannot be inadvertently opened. Administrative control includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator. Checking the valve position light in the control room is an adequate method for verifying every 24 hours that the purge valves are closed.

18.2.11.2 The Operating Agent Response

The containment isolation system and the containment isolation actuation are described in Sections 6.2.4, 7.3.2, and 7.3.8.

All lines penetrating the containment are identified in Figure 6.2.4-1. This figure also identifies the actuation signal(s) for isolation of those lines requiring isolation. The logic design for containment isolation is such that resetting of the containment isolation signal will not result in the loss of containment isolation. Once the initiating signal is reset, individual valves can be opened from the control room, if required. Reopening of isolation valves is performed on a valve-by-valve or line-by-line basis.

The containment isolation setpoint pressure (Hi-1) that initiates containment isolation (CIS-A) for non-essential penetrations has been reduced to the minimum compatible with normal operating conditions. Refer to SNUPPS letter dated March 15, 1984. The Technical Specifications establish a limit for containment pressure during normal operations. The Technical Specifications also contain the setpoint for Hi-1 which is based on the normal operation limit and instrument drift and accuracy.

Table 18.2-2 identifies systems as either essential or nonessential. Essential systems are those systems required to have isolation valves open for either post-accident safe shutdown or mitigation of the consequences of an accident.

The greatest number of lines are automatically isolated upon initiation of a containment isolation signal, Phase A (CIS-A). A safety injection signal (SIS) initiates a feedwater isolation signal (FWIS) and a steam generator blowdown isolation signal (SGBSIS). A CIS-A is initiated when a safety injection signal (SIS) is initiated. The diverse parameters sensed to initiate a SIS are low steam line pressure or low pressurizer pressure or high containment pressure (Hi-1). The CIS-A logic is shown on Figure 7.2-1, Sheet 8.

The main steam and related lines are automatically isolated upon initiation of a steam line isolation signal (SLIS). The diverse parameters sensed to initiate an SLIS are either low steam line pressure or high negative steam pressure rate and high containment pressure (Hi-2). The SLIS logic is shown on Figure 7.2-1, Sheet 8.

The lines supplying component cooling water to equipment inside the containment are isolated by CIS-B. A CIS-B is initiated by high containment pressure (Hi-3). It is not diverse, and is initiated with initiation of a containment spray actuation, which does utilize diversity. The CIS-B is shown on Figure 7.2-1, Sheet 8.

The containment purge system is isolated upon initiation of a containment purge isolation signal (CPIS). The diverse parameters sensed to initiate a CPIS are high containment radiation level and high containment purge exhaust radiation level, or a CIS-A signal. The CPIS logic is shown in Figure 7.3-1, Sheet 2.

The guidelines used for operability of containment purge isolation valves intended for use during plant operation comply with NRC criteria. Documentation of operability was provided by SNUPPS letter dated January 16, 1984. (Reference 11). The shutdown purge system isolation valves meet SRP 6.2.4, item II.3.f during operational conditions 1, 2, 3, and 4. Furthermore, these valves are verified to be closed in accordance with NUREG-0737, Item II.E.4.2.

All containment isolation valves are provided with control switches on the main control board. Manual actuation switches are provided for initiation of CIS-A, SLIS, and CPIS. In addition to diversity, these systems are redundant and meet safety-grade (Class 1E) criteria.

18.2.11.3 Conclusion

The design for the containment isolation system satisfies the requirements of Item II.E.4.2 of NUREG-0737.

18.2.12 ACCIDENT MONITORING INSTRUMENTATION (II.F.1)

18.2.12.1 NRC Guidance Per NUREG-0737

Introduction

Item II.F.1 of NUREG-0660 contains the following subparts:

1. Noble gas effluent radiological monitor.

2. Provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities (this requirement was inadvertently omitted from NUREG-0660; see Attachment 2 that follows, for position).

3. Containment high-range radiation monitor.

4. Containment pressure monitor.

5. Containment water level monitor.

6. Containment hydrogen concentration monitor.

NUREG-0578 provided the basic requirements associated with items 1 through 3 above. NRC staff letters issued to All Operating Nuclear Power Plants dated September 13, 1979 and October 30, 1979 provided clarification of staff requirements associated with items 1 through 6 above. Attachments 1 through 6 present the staff position on these matters.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed (see NUREG-0737, Section II.D.2), taking into consideration:

a. the use of this information by an operator during both normal and abnormal plant conditions,

b. integration into emergency procedures,

c. integration into operator training,

d. other alarms during emergency and need for prioritization of alarms.

(NOTE: Because of an editorial error, references to NUREG-0737, Appendix A in the following sections should actually be references to Appendix B.)

Attachment 1 Noble Gas Effluent Monitor

Position

Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

1. Noble gas effluent monitors with an upper range capacity of 10^5 Ci/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

2. Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal conditions (as low as reasonably achievable (ALARA)) concentrations to a maximum of 10^5 μCi/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

Clarification

1. Licensees shall provide continuous monitoring of high-level, post-accident releases of radioactive noble gases from the plant. Gaseous effluent monitors shall meet the requirements specified in Table II.F.1-1 [of NUREG-0737, presented below]. Typical plant effluent pathways to be monitored are also given in the table.

2. The monitors shall be capable of functioning both during and following an accident. System designs shall accommodate a design-basis release and then be capable of following decreasing concentrations of noble gases.

3. Offline monitors are not required for the PWR secondary side main steam safety valve and atmospheric relief valve discharge lines. For this application, externally mounted monitors viewing the main steam line upstream of the valves are acceptable with procedures to correct for the low energy gammas the external monitors would not detect. Isotopic identification is not required.

4. Instrumentation ranges shall overlap to cover the entire range of effluents from normal (ALARA) through accident conditions.

   The design description shall include the following information.

   a. System description, including:

      (i) Instrumentation to be used, including range or sensitivity, energy dependence or response, calibration frequency and technique, and vendor's model number, if applicable.

      (ii) Monitoring locations (or points of sampling), including description of methods used to ensure representative measurements and background correction.

      (iii) Location of instrument readout(s) and method of recording including description of the method or procedure for transmitting or disseminating the information or data.

(iv) Assurance of the capability to obtain readings at least every 15 minutes during and following an accident.

(v) The source of power to be used.

b. Description of procedures or calculational methods to be used for converting instrument readings to release rate per unit time, based on exhaust air flow and considering radionuclide spectrum distribution as a function of time after shutdown.

TABLE II.F.1-1

HIGH-RANGE NOBLE GAS EFFLUENT MONITORS

REQUIREMENT	Capability to detect and measure concentrations of noble gas fission products in plant gaseous effluents during and following an accident. All potential accident release paths shall be monitored.
PURPOSE	To provide the plant operator and emergency planning agencies with information on plant releases of noble gases during and following an accident.

Design Basis Maximum Range

Design range values may be expressed in Xe-133 equivalent values for monitors employing gamma radiation detectors or in microcuries per cubic centimeter of air at standard temperature and pressure (STP) for monitors employing beta radiation detectors (Note: 1 R/hr at 1 ft = 6.7 Ci Xe-133 equivalent for point source). Calibrations with a higher energy source are acceptable. The decay of radionuclide noble gases after an accident (i.e., the distribution of noble gases changes) should be taken into account.

10^5 µCi/cc	Undiluted containment exhaust gases (e.g., PWR reactor building purge, BWR drywell purge through the standby gas treatment system). Undiluted PWR condenser air removal system exhaust.

10^4 µCi/cc	Diluted containment exhaust gases (e.g., >10:1 dilution, as with auxiliary building exhaust air).
	BWR reactor building (secondary containment) exhaust air.
	PWR secondary containment exhaust air.
10^3 µCi/cc	Buildings with systems containing primary coolant or primary coolant offgases (e.g. PWR auxiliary building, BWR turbine buildings).
	PWR steam safety valve discharge, atmospheric relief valve discharge.
10^2 µCi/cc	Other release points (e.g., radwaste building, fuel handling/storage buildings).
REDUNDANCY	Not required; monitoring the final release point of several discharge inputs is acceptable.
SPECIFICATIONS	(None) Sampling design criteria per ANSI N13.1.
POWER SUPPLY	Vital instrument bus or dependable backup power supply to normal ac.
CALIBRATION	Calibrate monitors using gamma detectors to Xe-133 equivalent (1 R/hr @ 1 ft = 6.7 Ci Xe-133 equivalent for point source).
	Calibrate monitors using beta detectors to Sr-90 or similar long-lived beta isotope of at least 0.2 MeV.
DISPLAY	Continuous and recording as equivalent Xe-133 concentrations or µCi/cc or actual noble gases.
QUALIFICATION	The instruments shall provide sufficiently accurate responses to perform the intended function in the environment to which they will be exposed during accidents.
DESIGN CONSIDERATIONS	Offline monitoring is acceptable for all ranges of noble gas concentrations.
	Inline (induct) sensors are acceptable for 10^2 µCi/cc to 10^5 µCi/cc noble gases. For less than 10^2 µCi/cc, offline monitoring is recommended.

Upstream filtration (prefiltering to remove radioactive iodines and particulates) is not required; however, design should consider all alternatives with respect to capability to monitor effluents following an accident.

For external mounted monitors (e.g., PWR main steam line), the thickness of the pipe should be taken into account in accounting for low-energy gamma radiation.

Attachment 2 Sampling of Plant Effluents

Sampling of Plant Effluents

Position

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

Clarification

1. Licensees shall provide continuous sampling of plant gaseous effluent for postaccident releases of radioactive iodines and particulates to meet the requirements of the enclosed Table II.F.1-2 (from NUREG-0737, presented below). Licensees shall also provide onsite laboratory capabilities to analyze or measure these samples. This requirement should not be construed to prohibit design and development of radioiodine and particulate monitors to provide online sampling and analysis for the accident condition. If gross gamma radiation measurement techniques are used, then provisions shall be made to minimize noble gas interference.

2. The shielding design basis is given in Table II.F.1-2 [of NUREG-0737]. The sampling system design shall be such that plant personnel could remove samples, replace sampling media, and transport the samples to the onsite analysis facility with radiation exposures that are not in excess of the criteria of GDC-19 of 5-rem whole-body exposure and 75 rem to the extremities during the duration of the accident.

3. The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities which are approximately isokinetic (same velocity) with expected induct or instack air velocities. For accident conditions, sampling may be complicated by a reduction in stack or vent effluent velocities to below design levels, making it necessary to substantially reduce sampler intake flow rates to achieve the isokinetic condition. Reductions in air flow may well be beyond the capability of available sampler flow controllers to maintain isokinetic conditions; therefore, the staff will accept flow control devices which have the capability of maintaining isokinetic conditions with variations in stack or duct design flow velocity of +20 percent. Further departure from the isokinetic condition need not be considered in design. Corrections for nonisokinetic sampling conditions, as provided in Appendix C of ANSI 13.1-1969, may be considered on an ad hoc basis.

4. Effluent streams which may contain air with entrained water, e.g., air ejector discharge, shall have provisions to ensure that the adsorber is not degraded while providing a representative sample, e.g., heaters.

TABLE II.F.1-2

SAMPLING AND ANALYSIS OR MEASUREMENT OF HIGH-RANGE RADIOIODINE AND PARTICULATE EFFLUENTS IN GASEOUS EFFLUENT STREAMS

EQUIPMENT	Capability to collect and analyze or measure representative samples of radioactive iodines and particulates in plant gaseous effluents during and following an accident. The capability to sample and analyze for radioiodine and particulate effluents is not required for PWR secondary main steam safety valve and dump valve discharge lines.
PURPOSE	To determine quantitative release of radioiodines and particulates for dose calculation and assessment.
DESIGN BASIS SHIELDING ENVELOPE	10^2 μCi/cc of gaseous radioiodine and particulates, deposited on sampling media; 30 minutes sampling time, average gamma energy (E) of 0.5 MeV.

SAMPLING MEDIA

- Iodine > 90 percent effective adsorption for all forms of gaseous iodine.
- Particulates > 90 percent effective retention for 0.3 micron (μ) diameter particles.

SAMPLING CONSIDERATIONS

- Representative sampling per ANSI N13.1-1969.
- Entrained moisture in effluent stream should not degrade adsorber.
- Continuous collection required whenever exhaust flow occurs.
- Provisions for limiting occupational dose to personnel incorporated in sampling systems, in sample handling and transport, and in analysis of samples.

ANALYSIS

- Design of analytical facilities and preparation of analytical procedures shall consider the design basis sample.
- Highly radioactive samples may not be compatible with generally accepted analytical procedures; in such cases, measurement of emissive gamma radiations and the use of shielding and distance factors should be considered in design.

Attachment 3 Containment High-Range Radiation Monitor

Position

In containment radiation-level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

Clarification

1. Provide two radiation monitor systems in containment which are documented to meet the requirements of Table II.F.1-3 (of NUREG-0737, presented below).

2. The specification of 10^8 rad/hr in the above position was based on a calculation of postaccident containment radiation levels that included both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA (loss-of-coolant accident) containment environments, but gamma-sensitive instruments can be so qualified. In order to follow the course of an accident, a containment monitor that measures only gamma radiation is adequate. The requirement was revised in the October 30, 1979 letter to provide for a photon-only measurement with an upper range of 10^7 R/hr.

3. The monitors shall be located in containment(s) in a manner which will provide a reasonable assessment of area radiation conditions inside the containment. The monitors shall be widely separated so as to provide independent measurements and shall "view" a large fraction of the containment volume. Monitors should not be placed in areas which are protected by massive shielding and should be reasonably accessible for replacement, maintenance, or calibration. Placement high in a reactor building dome is not recommended because of potential maintenance difficulties.

4. For BWR Mark III containments, two such monitoring systems should be inside both the primary containment (drywell) and the secondary containment.

5. The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table 11.F.1-3 of NUREG-0737. Monitors that use thick shielding to increase the upper range will underestimate postaccident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gammas and are not acceptable.

TABLE II.F.1-3

CONTAINMENT HIGH-RANGE RADIATION MONITOR

REQUIREMENT	The capability to detect and measure the radiation level within the reactor containment during and following an accident.

RANGE	1 rad/hr to 10^8 rads/hr (beta and gamma) or alternatively 1 R/hr to 10^7 R/hr (gamma only).
RESPONSE	60 keV to 3 MeV photons, with linear energy response +20%) for photons of 0.1 MeV to 3 MeV. Instruments must be accurate enough to provide usable information.
REDUNDANT	A minimum of two physically separated monitors (i.e., monitoring widely separated spaces within containment).
DESIGN AND QUALIFICATION	Category 1 instruments as described in Appendix A (of NUREG-0737), except as listed below.
SPECIAL CALIBRATION	In situ calibration by electronic signal substitution is acceptable for all range decades above 10 R/hr. In situ calibration for at least one decade below 10 R/hr shall be by means of calibrated radiation source. The original laboratory calibration is not an acceptable position due to the possible differences after in situ installation. For high-range calibration, no adequate sources exist, so an alternate was provided.
SPECIAL ENVIRONMENTAL QUALIFICATIONS	Calibrate and type-test representative specimens of detectors at sufficient points to demonstrate linearity through all scales up to 10^6 R/hr. Prior to initial use, certify calibration of each detector for at least one point per decade of range between 1 R/hr and 10^3 R/hr.

Attachment 4 Containment Pressure Monitor

Position

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel and -5 psig for all containments.

Clarification

1. Design and qualification criteria are outlined in Appendix A (of NUREG-0737).

2. Measurement and indication capability shall extend to 5 psia for subatmospheric containments.

3. Two or more instruments may be used to meet requirements. However, instruments that need to be switched from one scale to another scale to meet the range requirements are not acceptable.

4. Continuous display and recording of the containment pressure over the specified range in the control room is required.

5. The accuracy and response time specifications of the pressure monitor shall be provided and justified to be adequate for their intended function.

Attachment 5 Containment Water Level Monitor

Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range instrument shall be provided for PWRs and cover the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000 gallon capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

Clarification

1. The containment wide-range water level indication channels shall meet the design and qualification criteria as outlined in Appendix A (of NUREG-0737). The narrow-range channel shall meet the requirements of Regulatory Guide 1.89.

2. The measurement capability of 600,000 gallons is based on recent plant designs. For older plants with smaller water capacities, licensees may propose deviations from this requirement, based on the available water supply capability at their plant.

3. Narrow-range water level monitors are required for all sizes of sumps but are not required in those plants that do not contain sumps inside the containment.

4. For BWR pressure-suppression containments, the emergency core cooling system (ECCS) suction line inlets may be used as a starting reference point for the narrow-range and wide-range water level monitors, instead of the bottom of the suppression pool.

5. The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.

Attachment 6 Containment Hydrogen Monitor

Position

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10 percent hydrogen concentration under both positive and negative ambient pressure.

Clarification

1. Design and qualification criteria are outlined in Appendix A (of NUREG-0737).

2. The continuous indication of hydrogen concentration is not required during normal operation.

   If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection.

3. The accuracy and placement of the hydrogen monitors shall be provided and justified to be adequate for their intended function.

18.2.12.2 The Operating Agent Response

Radiological Noble Gas Effluent Monitors

The WCGS design provides a wide range noble gas radiation monitor for each of the release paths listed below. Each monitor includes detectors covering the range shown below:

MONITOR	RANGE
Plant unit vent (GT-RE-21B)	10^{-7} to 10^{+5} μCi/cc
Radwaste building effluent (GH-RE-10B)	10^{-7} to 10^{+5} μCi/Cc

The locations of these monitors are shown on Radiation Zone Drawing Figure 12.3.2, sheet 4. Separate monitoring capability for the condenser air removal system is not provided because this system exhausts through the plant vent. The WCGS design includes gamma detectors to monitor the plume from the main steam atmospheric relief valves and to monitor the steam discharge from the turbine-driven auxiliary feedwater pump except for a small quantity of steam vented from the turbine glands. Additional information on this monitoring system is included in Reference 10.

Continuous indication is provided in the control room for each monitor. Each monitor is recorded in the control room.

The system/methods for monitoring and analysis is described in Reference 10. The readouts from the wide range monitors are input to the plant computers. This information is accessible from the Technical Support Center and the Emergency Operations Facility.

The procedures used to calibrate the instruments and calculate release rates have been incorporated into the WCGS procedures.

The following additional information was provided by Reference 10.

a. System description information, including energy dependence or response, range and sensitivity with respect to Xe-133, vendor model number, and methods used to assure representative measurements and background correction.

b. The calculational methods or procedures used for converting instrument readings to release rate per unit time based on exhaust air flow, and considering radionuclide spectrum distribution as a function of time after shutdown.

Provisions for Continuous Sampling of Plant Effluents for Post- Accident Releases of Radioiodines and Particulates

The WCGS design provides for continuous sampling of effluent radioiodines and particulates. The wide range gas monitors described above include the capability to obtain grab samples. The sampling accomplished by adsorption of iodine on charcoal filters or other media has been determined to be within the criteria of GDC-19 (see Reference 10). The sampling system criteria for all airborne monitoring systems are provided in Section 11.5.2.3.1.2. After collection, laboratory analyzers can be used to quantify iodine or particulates releases. A backup power source is provided for sample collection and analysis equipment to ensure operation for a minimum of 7 consecutive days. The WCGS procedures discuss the methods and counting equipment used to determine releases. The expected doses from obtaining and counting a sample have been calculated to range between 750 and 1750 mrem for a sample at the unit vent. These doses meet the requirements of NUREG-0737 and Regulatory Guide 1.97. Additional information regarding how WCGS meets the recommendations of Table II.F.1-2 and the provisions for approximate isokinetic sampling was provided by Reference 10.

Containment Radiation Monitors

The WCGS design meets the recommendations of Table II.F.1-3. The design includes two physically separated Class lE containment radiation monitors. The monitors are designated as 0-GT-RE-59 and 0-GT-RE-60. The detectors are located inside containment.

Indication is provided in the control room for each monitor, which is powered from a vital class lE power source. One channel is provided with a recorder, which is powered from vital class 1E power sources. Each monitor has a range up to 10^8 R/hr for gamma radiation. The monitors are sensitive down to 60 keV photons. The energy response of the monitors is linear (+20%) for energies between .1 Mev and 3 Mev. The equipment is seismically qualified for the location in which it is installed. The components are environmentally qualified for the environmental conditions to which they may be subjected.

Calibration of the monitors is addressed in procedures.

Additional information regarding the details of the design is described in Section 11.5.2.3.2.4.

Containment Pressure Indication

The WCGS design provides a dual range, redundant, continuous indication of containment pressure with both ranges (0 to 60 psig and -5 to 180 psig) indicated and recorded in the control room at the same time. The extended range indication loops are Class lE. As a minimum, their range is from minus 5 psig to three times the containment design pressure of 60 psig.

The response time of the containment pressure control room indication is 10 seconds for both the narrow and wide-range instrument channels. The accuracy of both the narrow and wide range channels is +4 percent of scale. The pressure monitor instrumentation meets the design and qualification criteria of NUREG-0737, Appendix B.

Containment Water Level Indication

The WCGS design includes in the control room continuous indication of the containment water level. This instrumentation is redundant and designed and qualified in accordance with Class lE requirements to meet the requirements of NUREG-0737, Appendix B. A single range is used to monitor both the containment normal sump level and the containment water level. The range is 13 feet, which covers 6 inches from the bottom of the containment normal sump to an elevation equivalent to 836,000 gallons. The upper limit of the range is greater than the maximum calculated water level. The accuracy of the indication is ±4 percent. The switchover of the low pressure safety injection pumps to recirculation is accomplished without the use of the containment water level indication.

A single range for the two RHR sump level indicators is used to measure the RHR sump level. Both RHR sump level indicator ranges are 11’ 7” (139”) measured from 1994’ 6” (30” above sump bottom) to 2006’ 11” (equivalent to 626,000 gallons). This indication issued to determine if adequate NPSH is available to the pumps taking suction from the containment.

Containment Hydrogen Concentration Monitor

The present design includes redundant safety-grade (Class lE) containment post-LOCA hydrogen analyzers with redundant Class lE indication provided in the control room. These monitors meet the design and qualification requirements of NUREG-0737, Appendix B. The hydrogen analyzers have a range of 0-10 percent hydrogen volume and are designed to operate under minimum and maximum containment design pressure.

The hydrogen analyzers are manually initiated following a LOCA. Once initiated, they provide a continuous measurement of hydrogen concentration within 30 minutes.

The sample points for the containment hydrogen monitors are in the vicinity of the intake of the containment air coolers and the post-accident water level.

18.2.12.3 Conclusion

The WCGS design provides six additional post-accident monitors specified in NUREG-0737 for accident diagnosis and mitigation. The Operating Agent has developed emergency operating procedures which detail use of each instrument specified during an accident.

The WCGS design is consistent with the recommendations of NUREG-0737, item II.F.1, for noble gas monitors.

The WCGS design includes features to sample plant effluents under accident conditions. The design of sampling system satisfies the criteria in NUREG-0737, item II.F.1.

The containment radiation monitor design meets the recommendations of item II.F.1-3.

The extended range containment pressure monitor design meets the recommendations of item II.F.1-3.

The WCGS design for containment water level indication meets the requirements of NUREG-0737, item II.F.1-5.

The WCGS design for the containment hydrogen monitors meet the requirements of NUREG-0737, item II.F.1-6.

18.2.13 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING (II.F.2)

18.2.13.1 NRC Guidance Per NUREG-0737

Position

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

Clarification

1. Design of new instrumentation should provide an unambiguous indication of ICC. This may require new measurements or a synthesis of existing measurements which meet design criteria (item 7).

2. The evaluation is to include reactor-water-level indication.

3. Licensees and applicants are required to provide the necessary design analysis to support the proposed final instrumentation system for inadequate core cooling and to evaluate the merits of various instruments to monitor water level and to monitor other parameters indicative of core-cooling conditions.

4. The indication of ICC must be unambiguous in that it should have the following properties:

    a. It must indicate the existence of inadequate core cooling caused by various phenomena (i.e., high-void fraction-pumped flow as well as stagnant boil-off); and,

    b. It must not erroneously indicate ICC because of the presence of an unrelated phenomenon.

5. The indication must give advanced warning of the approach of ICC.

6. The indication must cover the full range from normal operation to complete core uncovery. For example, water-level instrumentation may be chosen to provide advanced warning of two-phase level drop to the top of the core and could be supplemented by other indicators such as incore and core-exit thermocouples provided that the indicated temperatures can be correlated to provide indication of the existence of ICC and to infer the extent of core uncovery. Alternatively, full-range level instrumentation to the bottom of the core may be employed in conjunction with other diverse indicators such as core-exit thermocouples to preclude misinterpretation due to any inherent deficiencies or inaccuracies in the measurement system selected.

7. All instrumentation in the final ICC system must be evaluated for conformance to Appendix A (to NUREG-0737), "Design and Qualification Criteria for Accident Monitoring Instrumentation," as clarified or modified by the provisions of items 8 and 9 that follow. This is a new requirement.

8. If a computer is provided to process liquid-level signals for display, seismic qualification is not required for the computer and associated hardware beyond the isolator or input buffer at a location accessible for maintenance following an accident. The single-failure criteria of item 2, Appendix A, need not apply to the channel beyond the isolation device if it is designed to provide 99 percent availability with respect to functional capability for liquid-level display. The display and associated hardware beyond the isolation device need not be Class IE, but should be energized from a high-reliability power source which is battery backed. The quality assurance provisions cited in Appendix A, item 5, need not apply to this portion of the instrumentation system. This is a new requirement.

9. Incore thermocouples located at the core exit or at discrete axial levels of the ICC monitoring system and which are part of the monitoring system should be evaluated for conformity with Attachment 1, "Design and Qualification Criteria for PWR Incore Thermo-couples," which is a new requirement.

10. The types and locations of displays and alarms should be determined by performing a human factors analysis taking into consideration:

    a. The use of this information by an operator during both normal and abnormal plant conditions.

    b. Integration into emergency procedures.

    c. Integration into operator training.

    d. Other alarms during emergency and need for prioritization of alarms.

ATTACHMENT 1, DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED-WATER REACTOR INCORE THERMOCOUPLES

1. Thermocouples located at the core exit for each core quadrant, in conjunction with core inlet temperature data, shall be of sufficient number to provide indication of radial distribution of the coolant enthalpy (temperature) rise across representative regions of the core. Power distribution symmetry should be considered when determining the specific number and location of thermocouples to be provided for diagnosis of local core problems.

2. There should be a primary operator display (or displays) having the capabilities which follow:

   a. A spatially oriented core map available on demand indicating the temperature or temperature difference across the core at each core exit thermocouple location.

   b. A selective reading of core exit temperature, continuous on demand, which is consistent with parameters pertinent to operator actions in connecting with plant-specific inadequate core cooling procedures. For example, the action requirement and the displayed temperature might be either the highest of all operable thermocouples or the average of five highest thermocouples.

   c. Direct readout and hard-copy capability should be available for all thermocouple temperatures. The range should extend from 200 F (or less) to 1800 F (or more).

   d. Trend capability showing the temperature-time history of representative core exit temperature values should be available on demand.

   e. Appropriate alarm capability should be provided consistent with operator procedure requirements.

   f. The operator-display device interface shall be human-factor designed to provide rapid access to requested displays.

3. A backup display (or displays) should be provided with the capability for selective reading of a minimum of 16 operable thermocouples, 4 from each core quadrant, all within a time interval no greater than 6 minutes. The range should extend from 200 F (or less) to 2300°F (or more).

4. The types and locations of displays and alarms should be determined by performing a human-factors analysis taking into consideration:

   a. the use of this information by an operator during both normal and abnormal plant conditions,

   b. integration into emergency procedures,

   c. integration into operator training, and

   d. other alarms during emergency and need for prioritization of alarms.

5. The instrumentation must be evaluated for conformance to Appendix B (to NUREG-0737), "Design and Qualification Criteria for Accident Monitoring Instrumentation," as modified by the provisions of items 6 through 9 which follow.

6. The primary and backup display channels should be electrically independent, energized from independent station Class lE power sources, and physically separated in accordance with Regulatory Guide 1.75 up to and including any isolation device. The primary display and associated hardware beyond the isolation device need not be Class lE, but should be energized from a high-reliability power source, battery backed, where momentary interruption is not tolerable. The backup display and associated hardware should be Class lE.

7. The instrumentation should be environmentally qualified as described in Appendix B, Item 1, except that seismic qualification is not required for the primary display and associated hardware beyond the isolater/input buffer at a location accessible for maintenance following an accident.

8. The primary and backup display channels should be designed to provide 99 percent availability for each channel with respect to functional capability to display a minimum of four thermocouples per core quadrant. The availability shall be addressed in Technical Specifications.

9. The quality assurance provisions cited in Appendix B, item 5, should be applied except for the primary display and associated hardware beyond the isolation device.

18.2.13.2 The Operating Agent Response

Item II.F.2 of NUREG-0737 specifies the following as required documentation concerning instrumentation for detection of inadequate core cooling (ICC):

1. A description of the proposed final system including:

   a. A final design description of additional instrumentation and displays.

   b. A detailed description of existing instrumentation system (e.g., subcooling meters and incore thermocouples), including parameter ranges and displays, which provide operating information pertinent to ICC consideration.

   c. A description of any planned modifications to the instrumentation systems described in item 1.b above.

2. The necessary design analysis, including evaluation of various instruments to monitor water level, and available test data to support the design described in item 1 above.

3. A description of additional test programs to be conducted for evaluation, qualification, and calibration of additional instrumentation.

4. An evaluation, including proposed actions, of the conformance of the ICC instrument system to this document, including Attachment 1 and Appendix B. Any deviations should be justified.

5. A description of the computer functions associated with ICC monitoring and functional specifications for relevant software in the process computer and other pertinent calculators. The reliability of nonredundant computers used in the system should be addressed.

6. A current schedule, including contingencies, for installation, testing and calibration, and implementation of any proposed new instrumentation or informative displays.

7. Guidelines for use of the additional instrumentation, and analyses used to develop these procedures.

8. A summary of key operator action instructions in the current emergency procedures for ICC and a description of how these procedures will be modified when the final monitoring system is implemented.

9. A description and schedule commitment for any additional submittals which are needed to support the acceptability of the proposed final instrumentation system and emergency procedures for ICC.

The following is a discussion of each of the above items as they relate to the WCGS instrumentation for detection of ICC:

1. The system used at the WCGS unit to detect ICC consists of a reactor vessel level instrumentation system (RVLIS) and a thermocouple/core cooling monitor system (T/CCMS).

   ICC Defined

   ICC was defined in WCAP-9754, "Inadequate Core Cooling Studies of Scenario With Feedwater Available Using the NOTRUMP Computer Code," as a high temperature condition in the core such that the operator is required to take action to cool the core before significant damage occurs. During the design basis small loss-of-coolant accident, the operator is not required to take any action to recover the plant other than to verify the operable status of the safeguards equipment, trip the reactor coolant pumps (RCPs) when appropriate plant conditions are met, and initiate cold and hot leg recirculation procedures as required. In the design basis small Loss of Coolant Accident (LOCA), a period of cladding heat-up may occur prior to automatic core recovery by the safeguards equipment. The heat-up period is dependent upon the break size and ECCS performance.

For a LOCA equivalent in size to approximately 6 inches diameter or less, an ICC condition can only occur if two or more failures occur in the ECCS. As indicated in WCAP-9754, an ICC condition can be calculated by hypothesizing the failure of all high head safety injection (HPSI) for LOCAs of approximately 1 inch in size. For a 4-inch equivalent-size LOCA, one can hypothesize an ICC condition by assuming the failure of all HPSI as well as the failure of the passive accumulator system (a truly incredible sequence of events).

For LOCAs of sizes of 6 inches or less, the approach to ICC is unambiguous to the reactor operators. The first indication of a possible ICC situation is the indication that some of the ECCS pumps have failed to start or are not delivering flow. The second indication of a possible ICC situation is the occurrence of a saturation condition in the primary coolant system as indicated on the subcooling monitor. Shortly after the second indication, the RVLIS would start to indicate the presence of steam voids in the vessel. At some point in time the RVLIS will indicate a collapsed liquid level below the top of the core. The core exit thermocouples (T/Cs) will begin to indicate superheated steam conditions. The RVLIS and core exit T/C behavior provide unambiguous indications to the operator to follow the ICC mitigation procedure.

WCAP-9754 indicates that the selected core exit T/Cs will read 1200°F at approximately 11,000 seconds after the initiation of a 1-inch LOCA with the loss of all High Pressure Safety Injection. The Generic Westinghouse Emergency Operating Procedure (EOP) Guideline instructs the operator to pursue ICC mitigation procedures when these conditions are reached. The 4-inch LOCA indicates 1200°F at about 1350 seconds. By following the Westinghouse recommended EOPs, the operators have earlier indication of a possible ICC situation.

Realistically, an indication of an ICC condition would not occur until the primary coolant system has drained sufficiently for the reactor vessel mixture level to fall below the top of the core. Westinghouse has performed analyses which indicate that the upper head will drain below the top of the guide tubes before ICC conditions exist. The guide tubes are the only flow path from the upper head to the upper plenum. In WCAP-9754, it was found that ICC situations would not result for LOCAs equivalent in size to approximately 6 inches or less without two or more failures in the ECCS. In both specific scenarios examined in WCAP-9754, a 1-inch and 4-inch small LOCA, the upper head and upper plenum had completely drained before the onset of an ICC condition.

Large break LOCAs consist of LOCAs in which the fluid behavior is inertially dominated. Small break LOCAs, on the other hand, have the fluid behavior dominated by gravitational effects. For LOCAs which are significantly larger than an equivalent 6-inch break, the ECCS has the maximum potential for flow delivery, since the primary coolant system is at low pressure. Analyses for LOCAs in this range indicate ambiguous behavior of the core exit T/Cs and RVLIS early in the accident due to dynamic blowdown effects. This behavior is temporary, and the core exit T/Cs and the RVLIS will indicate the progress being made by the ECCS in recovering the core. When the core exit T/Cs and RVLIS may be temporarily providing ambiguous indications, no manual action is needed or useful. Later in the accident when manual action may be useful, the core exit T/Cs and RVLIS provide an unambiguous indication of ICC if it exists. This unambiguous indication may be present as early as 30 seconds after the initiation of the LOCA for a double ended guillotine rupture of a main coolant pipe.

It follows from the above discussion that, for ICC considerations, a reasonable definition of large breaks are breaks that are significantly larger than an equivalent 6-inch break. Note: The large and small break LOCA has been redefined as noted in section 6.3 and 15.6.5.

Reactor Vessel Level Instrumentation System

The WCGS design provides redundant safety-grade (Class 1E) reactor vessel water level instrumentation. The four reactor vessel water level indicators (LI-1311, LI-1312, LI-1321, and LI-1322) are located on the main control board reactor auxiliaries console, RL-021. The reactor vessel level instrumentation system (Figures 18.2-13 and 5.1-1) utilizes two sets of two d/p cells. These cells measure the pressure differential between the bottom of the reactor vessel and the top of the vessel. This d/p measuring system utilizes cells of differing ranges to cover different flow behavior with and without pump operation as discussed below:

a. Reactor Vessel - Narrow Range (ΔPb)

This measurement provides an indication of reactor vessel level from the bottom of the reactor vessel to the top of the reactor during natural circulation conditions.

b. Reactor Vessel - Wide Range (ΔPc)

This instrument provides an indication of reactor core and internals pressure drop for any combination of operating RCPs. Comparison of the measured pressure drop with the normal, single-phase pressure drop provides an approximate indication of the relative void content or density of the circulating fluid. The indication of coolant density is significant only when the subcooling is near zero. This instrument monitors coolant conditions on a continuing basis during forced flow conditions. Calculations were performed to obtain an estimate of the differential pressure that the wide range instrument measures with all pumps operating, from ambient temperature to operating temperature. The calculations employ the same methods used to estimate reactor coolant flow for plant design and safety analysis. These calculations were used primarily to define the instrument span and to provide an estimate for the function that compensates the differential pressure signal over the full temperature range, i.e., that results in the wide range display indicating 100 percent over the full temperature range with all pumps operating, pumping subcooled coolant. During the initial plant startup following installation of the instrumentation, wide range differential pressure data is obtained and used to confirm or revise the compensation function so that a 100-percent output is obtained at all temperatures. Since the calculated compensation function was verified by plant operating data, any uncertainties in the flow and differential pressure estimates are eliminated.

The relationships used in the analog-based RVLIS system to calculate density corrections are from the ASME Steam Tables, dated 1967. These relationships are implemented within the system by means of memory circuits that generate an output signal which is a predetermined function of the input signal. The predetermined functions produce specific scopes which are added together to obtain the required input-output relationships.

To provide the required accuracy for level measurement, temperature measurements of the impulse lines are provided. These measurements, together with existing reactor coolant temperature measurements and wide-range RCS pressure, are employed to compensate the d/p transmitter outputs for differences in system density and reference leg density, particularly during the change in the environment inside the containment structure following an accident.

Resistance Temperature Detector (RTD) sensors are installed on every independently run vertical section of impulse line, to provide a measurement for density compensation of the reference leg. If the vertical section of impulse line runs through two compartments separated by a solid floor, an RTD sensor is installed in each compartment. The RTD is installed at the midpoint of each vertical section based on the assumption that the temperature in the compartment is uniform or that the temperature distribution is linear in the vicinity of the impulse line. An allowance for a 5 F difference between the true average impulse line temperature and the RTD measurement is included in the measurement uncertainty analysis. This allowance permits a significant deviation from a linear gradient; e.g., 20 percent of the impulse line could differ by as much as 25 F from a linear gradient without exceeding the allowance. During normal operation, forced circulation from cooling fans is expected to maintain reasonably uniform compartment temperatures. During the LOCA, turbulence within a compartment due to release of steam would also produce a reasonably uniform temperature. Note that the impulse lines are protected from direct jet impingement by metal instrument tubing channels.

The WCGS design does not include hot leg impulse lines. The layout of the impulse line from the upper head is arranged to prevent or minimize the impact of drainage during an accident. In general, however, the water in the impulse line is cooler than the water in the reactor, and there is sufficient subcooling overpressure in the line so that very little, if any, of the water would flash to steam during a depressurization or containment heat-up. Heat conduction along the small diameter piping and tubing would be insufficient to result in flashing in a significant length of piping.

The connection to the upper head from a spare control rod drive mechanism port drops or slopes down from the highest point of the vessel connection to the sensor bellows mounted on the refueling canal wall, so water would be retained in this piping. Draining of the vertical section immediately above the reactor vessel has no effect on the level measurement, since this section is included in the operating range of the instrument. Draining of the horizontal portion of vessel vent piping above the vessel also has no effect on the measurement, since no elevation head is involved.

The majority of the impulse line length is in capillary tubing sealed at both ends with a bellows (sensor bellows at the reactor end, hydraulic isolator at the containment penetration end), so water would be retained in the impulse line at all times. The water is demineralized, deaerated and pressurized by reactor pressure. In the event of a LOCA, the water in the capillary lines would not flash since it is in a sealed system. The lines contain no noncondensible gases and are not in a radiation environment sufficient for the dissociation of water.

Since there is no mechanism for concentration of gases at the top of the reactor vessel during normal operation, the connection to the top of the vessel would contain, at most, the normal quantity of dissolved gases in the coolant, and the subcooling pressure during an accident would maintain this quantity of gas in solution.

Redundancy of the two instrument trains of the RVLIS is not compromised by having a shared upper reactor vessel tap since it is not conceivable that the tap will fail either from plugging or breaking. Freedom from plugging is enhanced by 1) use of stainless steel connections which preclude corrosion products, and 2) absence of mechanisms, such as flow for concentrating boric acid. It is also inconceivable that the tap will break because it is in a protected area. Even if the share tap does fail, it should be recognized that RVLIS is not a protection system initiating automatic action, but a monitoring system with adequate backup monitoring such as by core exit thermocouples for operator correlation.

Additional information (i.e., analyses, evaluations) concerning the Westinghouse generic reactor vessel level instrumentation system has been submitted to the NRC via Reference 7. The specific hardware for WCGS is not exactly as documented in Reference 7, since the WCGS design does not include a measurement of reactor vessel level above the hot legs. However, the analyses, evaluations, and conclusions contained in Reference 7 are applicable to WCGS, since they are not sensitive to the above mentioned design difference.

The RVLIS measurement from top to bottom of the vessel measures the level in the following regions: top of vessel to top of guide tube; inside guide tube from top to upper support plate; upper plenum; reactor core; and lower plenum. During a LOCA, the RVLIS would measure the water level in the upper head only until the level drops to the top of the guide tubes; RVLIS would then measure level reduction in the guide tubes and upper plenum. The water remaining in the upper head below the top of the guide tubes is not measured by RVLIS. This water would eventually drain through small holes into the guide tubes and downcomer, and this drainage would be accomplished within a few minutes, depending on the accident. In any case, the water temporarily retained in the upper head would have no effect on the RVLIS indication. (It should be noted that the WFLASH Code, which was used to analyze RVLIS performance, includes calculation of water mass and pressure in the upper head, but this water mass is not included in the calculation of mixture level; hence, the mixture level is indicated only below the elevation of the upper support plate.)

Environmental qualification of the reactor vessel level instrumentation system high volume sensor was completed in accordance with 10 CFR 50.49.

Thermocouple/Core Cooling Monitor System

The T/CCMS is a core exit thermocouple/core cooling detection system which provides presentation and display of the status of the core heat removal capability to both the plant operators and the technical support center. In the control room, the two subcooling temperature indicators are located immediately above the four level indicators on the vertical portion of the control board, RL-022. The core exit thermocouple display is mounted on the subcooling monitor cabinet, RP-081. The system consists of redundant channels and output trains of thermocouple measurements, wide-range hot and cold-leg RTD temperatures, and reactor pressure signals. These parameters are used by the system to display thermocouple temperatures and to calculate saturation temperatures and margin of saturation (Tsat margin), which is often referred to as subcooling. The calculations are performed by the system which is based on Advanced Logic System (ALS) Platform and data handling devices.

Thermocouple Monitor

The core exit thermocouple portion of the ICC system is arranged as follows:

a. Primary system

   The primary system measures all the thermocouples via isolators located in the qualified backup system cabinet.

b. Backup system

   The backup system consists of two channels, each monitoring approximately half of the 47 core outlet thermocouples. The system has separation and redundancy as well as qualification to comply with Appendix B of NUREG-0737 (see the discussion of item 4 below).

Core Cooling Monitor

The core cooling monitor portion of ICC system compares core outlet thermocouple temperatures and hot and cold leg RTD temperatures with the saturation temperature based on the lowest of three pressure signals. This system has separation and redundancy as well as qualification to comply with Appendix B of NUREG-0737 (see the discussion of item 4 below).

One of the indicators of an approach to an ICC situation is the response of the core exit thermocouples (T/Cs) to the presence of superheated steam. The core exit thermocouples do not provide an indication of the amount of core voiding. Response of the core exit T/Cs provides a direct indication of the existence of ICC, the effectiveness of ICC recovery actions, and restoration of adequate core cooling. The core is adequately cooled whenever the vessel mixture level is above the top of the core, and the core may have a significant void fraction and still be adequately cooled.

The thermocouple/core cooling monitor combines the functions of monitoring for excessive core exit thermocouple temperatures and monitoring both core exit thermocouple temperatures and hot and cold leg RTD temperatures for saturation margin (Tsat meter).

The system consists of two redundant channels, each monitoring half of the core outlet thermocouples, and four hot and cold leg RTDs. Three reactor pressure input signals are used with the auctioneered low pressure used by the ALS Platform to perform the Tsat margin function. The thermocouple temperatures are corrected for reference junction temperature with three reference junction temperature signals input to each channel. (All of the thermocouples connected to one channel are from one reference junction unit).

The system's two redundant trains utilize the following safety-grade equipment:

a. Thermocouples

b. Reference junction boxes

c. RTDs

d. Termination Panel

e. ALS Platform

f. Flat Panel display

g. Analog meters

h. Digital Recorder (Black Box)

i. Power supplies

j. Connections and cabling

The equipment listed above and shown in Figure 18.2-12 has been designed to satisfy the requirements of IEEE Standard 279. This safety-grade system is isolated from the non-Class 1E plant computer, technical support center, and data links by qualified isolation devices. Details of isolation device qualification for TCCM upgrade can be found in Westinghouse letter LTR-EQ-13-228 "Results of ALS-601 fault and Isolation Barrier Testing for TCCM."

The system can display individual thermocouple temperatures and provides two levels of alarm when preset temperatures are exceeded. The display is a flat panel display located at the processing cabinets, behind the main control board.

The thermocouple monitor can calculate and display core outlet temperature quadrant tilts based on thermocouple temperatures. The tilts calculated by each unit are based on half the total number of core thermocouples. This information is also available to the operator at the main control board via the plant computer.

The core cooling monitor compares core outlet thermocouple temperatures and hot and cold leg RTD temperatures with the saturation temperature based on the lowest of three pressure signals. Two levels of alarm are provided for the core cooling (Tsat) monitor function. The margin to saturation is displayed on two redundant analog meters on the vertical section of the main control board and are visible to an operator at the control console.

The thermocouple/core cooling monitor provides information to the operator that assists in the performance of the required manual safety functions following a Condition II, III, or IV event. This includes information relative to maintaining the plant in a Hot Standby condition or to proceeding to a cold shutdown condition consistent with the Technical Specification limits.

At WCGS, the core exit T/Cs protrude slightly from the bottom of the upper core plate support columns. In this location, they measure the temperature of the fluid leaving the core region through the flow passages in the upper core plate. Flow from the upper head must enter the upper plenum via the control rod drive guide tubes before being able to enter the upper core plate flow passages. In addition, the LOCA blowdown depressurization behavior must be such that there is a flow reversal for the core exit T/Cs to detect the upper head fluid temperature. The upper head fluid is expected to mix with the upper plenum fluid as it drains from the upper head.

The potential for core exit T/C cooling from colder upper head fluid, while the core has an appreciable void fraction, is not viewed as a potential problem for the detection of an inadequate core cooling situation. Although some Semiscale tests indicated core voiding while the upper head was liquid solid, these tests do not imply that the core exit T/Cs would give an ambiguous indication of ICC calculations for a Westinghouse PWR, and consideration of the core exit T/C design would not result in ambiguous ICC indications.

Additional information concerning the thermocouple/core cooling monitor system is provided in Table 18.2-3.

2. Reference 7 provides a design analysis and evaluation of the instrumentation for detection of ICC. Additional information is provided below.

   The reactor coolant pressure and temperature signals originate from the existing wide-range pressure and hot leg RTDs already installed in the plant, and the uncertainties for these instruments are understood. The pressure uncertainty is ± 60 psi, and the temperature uncertainty is ± 6 F, resulting in a maximum RVLIS uncertainty contribution of ± 2.3 percent when the vessel is full. This uncertainty is smaller when the level is at the elevation of the reactor core. This contribution to the total uncertainty would increase roughly in proportion to an increase in the pressure or temperature measurement uncertainty.

   A system accuracy of ± 6 percent water level was a target value established during the conceptual design and was related to the dimensions of the reactor vessel (12 percent from nozzles to top of core) and core (30 percent), and the usefulness of the measurement during an accident. The individual uncertainties, resulting from random effects, were combined statistically to obtain the overall instrument system accuracy. Some of the individual uncertainties vary with conditions such as system pressure. Table 18.2-4 identifies the individual uncertainties for the narrow range measurement while at a system pressure of 1200 psia.

The statistical combination (square root of the sum of the squares) of the individual uncertainties described above resulted in an overall system instrumentation uncertainty of ± 3.9 percent of the level span for the narrow range indication of approximately 40 feet, or ± 1.5 feet, at a system pressure of 1200 psia. Examples of the uncertainty at other system pressures are:

Uncertainty = ± 3.6 percent at 400 psia
Uncertainty = ± 4.2 percent at 2000 psia

By letter dated February 20, 1986, (Reference 15) Westinghouse reported to the NRC the results of an evaluation relative to the consequences of larger than expected post-accident errors on the T/CCMS. These errors, which are identified in WCAP 8587 (Reference 16), affected subcooling margin calculations, the use of T/Cs for ICC indication and the use of T/Cs as temperature compensation for RVLIS. Based on the revised error values, restrictions were placed on use of T/Cs for RVLIS and subcooling margin calculations and the EOP Guidelines were revised to incorporate new ICC indication setpoints and revised accuracy requirements were developed for RVLIS. Modifications to plant hardware and procedures, required by the larger than expected T/CCMS errors, have been implemented at WCGS.

An analysis of the RVLIS hydraulics, an independent analysis of the hydraulics by Oak Ridge National Laboratory (ORNL), and the results of testing at the Semiscale Test Facility in Idaho generally support a response time (50 percent response to a step change in level) of 3 seconds or less for the hydraulics. There are, however, two types of transients which affect the RVLIS response: a change in level and a change in system pressure. The major factors that influence the RVLIS hydraulics response to these two types of transients are the fluid volume within the RVLIS system and the length of capillary tubing connected to the d/p transmitter. For a level transient, the volume required to displace the transmitter bellows and the total length of capillary tubing are the significant parameters. Although the capillary tubing length (typically 600 feet) and diameter (0.089 inch) represent a significant resistance to flow, the volume required for a full span deflection of the transmitter bellows is small (0.1 cubic inch). The sensor and hydraulic isolator bellows displacement spring constants introduce a small error in the measured level but do not impact the response time of the system.

For a system pressure transient, the total fluid volume of the RVLIS system and the difference in length between the two capillary lines connected to the d/p transmitter are the significant parameters. In theory, the transmitter would not respond to a change in pressure if the two capillary lines were equal in length. In practice, plant layout requirements result in lengths differing by as much as 100 feet. During a system pressure change, the water volume in the RVLIS system will expand or contract a small amount, but measurable pressure drops will develop in the capillary lines as the small volumes move to equalize pressure. The d/p transmitter will indicate a differential pressure or offset caused by one line being longer than the other. For a reasonably rapid transient of 100 psi per second imposed on an RVLIS system having a difference in line lengths of 100 feet, the offset or apparent level change would approach about 2 feet of water, and the offset would remain until the pressure transient is terminated. After the initial blowdown from a small break, the pressure transients would be much slower, and the level offset would be negligible. Much larger offsets approaching full scale deflection could occur (and have been observed during a large break test at Semiscale) during the initial large break transient, but an RVLIS output during this short period of less than 2 minutes would not otherwise be useful or required for actions associated with ICC. In addition to the hydraulics response characteristics, the RVLIS electronics incorporate an adjustable lag to filter hydraulic noise when reactor coolant pumps are operating. The lag time constant is adjustable up to 10 seconds. The response time associated with the rest of the electronics has essentially no impact on the total response time, which is within 10 seconds.

Blockage in the core will increase the frictional pressure drop and increase the total differential pressure across the vessel. This would be reflected as a higher RVLIS indication. The increase in the RVLIS is most significant under forced flow conditions when the reactor coolant pumps are operating.

In order for blockage to be present, the core would have to have been uncovered for a prolonged period of time. A low RVLIS indication along with a high core exit thermocouple indication would have been indicated during this time. If the RCPs had been operating throughout the transient, there would have been sufficient cooling to prevent significant core damage. Therefore, for significant blockage to exist during pump operation, the operator would have restarted the pumps after an ICC condition had existed for a period of time. Based on the history of the transient, the operator would know that the RVLIS would read higher than expected. Although the RVLIS would read high, it would still follow the trend in vessel inventory. The operator would be able to monitor the recovery with the RVLIS.

Under natural circulation conditions, the impact of core blockage is not expected to be large. Although the RVLIS indication will read slightly higher than normal, the RVLIS will still trend with the vessel inventory and provide useful information for monitoring the recovery from ICC. ICC will have been indicated at an earlier time, before a significant amount of core blockage has occurred. The operator would know that the RVLIS could read slightly high, based on the history of the transient.

Reverse flow in the vessel tends to decrease the d/p across the vessel which would cause the RVLIS to indicate a lower collapsed level than actually exists. The low indication would not cause the operator to take unnecessary actions, since an ICC recovery action would be based on a coincidence of a low level indication and a high core exit thermocouple indication (>700°F). In a reverse flow situation, the core exit thermocouples would be responding to the saturated temperature of the water flowing from the upper plenum to the core, so a high thermocouple indication of >700°F would not occur. It is important to note that large reverse flows are not expected to occur for breaks smaller than 6 inches in diameter during the time that the core is uncovered. Large reverse flow rates may occur early in the blowdown transient for large diameter breaks, but, as is discussed below, it is not necessary to use the RVLIS as a basis for operator action for breaks in this range.

During the course of a LOCA transient, the upper plenum will experience voiding before the upper head. The voids in the upper plenum will be indicated by a lower RVLIS reading. The RVLIS will not indicate where the voiding is occurring, but at this point in the transient, it is not necessary to know the location of the region of voiding. In the early part of the transient, when the mixture level is above the top of the guide tube in the upper head, it is sufficient for the operator to know that the vessel inventory is decreasing, irrespective of the region where voiding is occurring. The fluid in the upper head does not affect the RVLIS indication after the upper head has drained to below the top of the guide tubes. The upper head will drain before the onset of ICC, and there is not an ambiguous indication during the period of time RVLIS is used.

Experience in overranging of differential pressure instruments has been obtained in previous applications of differential pressure capsules similar to those used in RVLIS. In dual range flow (differential pressure) applications, the "low flow" transmitter (and/or gauges) are overranged to 300 percent or greater by normal flow rates, yet provide reliable metering when required for start-up.

Also, test data exist on the basic transmitter design showing about 0.5 percent effect on calibration with 24 hours exposure to 3000 psig overrange. All units are similarly exposed to this overrange for 5 minutes in both directions as a part of factory testing.

There have been instances involving accidental overrange of these instruments (including RVLIS) as the result of leakage or operator errors where full line pressure overranges have occurred for up to several weeks with minimal effect on instrument accuracy.

Based upon this experience and test data, it is expected that reliable measurements can be made by the selected overranged instrument designs used for RVLIS. On-line calibration capability is provided if needed to support gathering of statistical data.

The following are conditions which could cause the DP level system to give ambiguous indications:

a. When the downcomer is highly voided and the accumulators inject, the cold accumulator water condenses some of the steam in the downcomer which causes a local depressurization. The local depressurization will lower the pressure at the bottom of the vessel which will lower the differential pressure across the vessel, causing an apparent decrease in level indication. The lower pressure in the downcomer also causes the mixture in the core to flow to the lower plenum, causing an actual decrease in level. The period of time when the RVLIS indication is lower than the actual collapsed liquid level is brief.

   An example of a situation in which this phenomenon may occur is when the reactor coolant pumps have been running for a long period of time in a small break transient. After the RCS loops have drained and the pumps are circulating mostly steam, the level in the downcomer will be depressed. A large volume of steam will be present in the downcomer, above the low mixture level, which allows a large amount of condensation to occur. For most small break transients, the reactor coolant pumps are tripped early in the transient, and the downcomer mixture level will remain high, even in cases where ICC occurs. When the downcomer level is high, the effect of accumulator injection on the RVLIS indication is minor.

b. When the upper head begins to drain, the pressure in the upper head decreases at a slower rate than the pressure in the rest of the RCS. This is due to the upper head region behaving much like the pressurizer. The higher resistance across the upper support plate relative to the rest of the RCS prevents the upper head from draining quickly. This situation only exists until the mixture level in the upper head falls below the top of the guide tubes. At this time, steam is allowed to flow from the upper plenum to the upper head, and the pressure equilibrates. While the upper head is behaving like a pressurizer, the vessel differential pressure is reduced, and the RVLIS indicates a lower than actual collapsed liquid level.

This phenomenon is discussed in the summary report on the Westinghouse RVLIS for Monitoring ICC, December 1980 relative to the 3-inch cold leg break. Since that time, the upper head modeling has been investigated in more detail. It was found that the modeling used at that time assumed a flow resistance that was too high for the guide tubes. Subsequent analyses have shown that the pressurizer effect has less impact on the vessel differential pressure than was originally shown. There is very little impact on the results after the level drains below the top of the guide tubes. The pressurizer effect is still believed to exist, and it becomes more significant as break size increases. The interval of time when the upper head behaves like a pressurizer is brief, and the RVLIS will resume trending with the vessel level after the top of the guide tubes uncovers. The reduced RVLIS indication will not cause the operator to take any non-conservative action, even if a level below the top of the core is indicated, since the core exit thermocouples are used as a corroborative indication of the approach to ICC.

c. The normal condition for continuous upper plenum injection (UPI) occurs only with the operation of the low head safety injection pumps, which does not occur until a pressure of under 200 psi is realized. The RVLIS may not accurately trend with vessel level during the initial start of UPI. During this short period of time, the cold water being injected mixes with the steam in the upper plenum causing condensation. This condensation will occur faster than the system response. The system will equilibrate after a short period of time. Upon equilibrating, the system will continue to accurately trend with the vessel level.

In the range of break sizes where RVLIS is most useful in detecting the approach to ICC, the system pressure will equilibrate at a level above the pressure where UPI will normally occur. It is important to note that the flow from the low head pumps is sufficient to recover the core, and no operator action based on the RVLIS indication will be necessary.

For the vast majority of small breaks, the condition of upper plenum injection does not cause a significant impact. For the remainder, the impact is very small and within tolerable limits.

d. During the time when the distribution of voids in the vessel is changing rapidly, there can be a large change in the two-phase mixture level with very little change in collapsed mixture level. The use of the RVLIS, in conjunction with the core exit thermocouples, is still valid for this situation, however. The only event that has been identified which could cause a large void redistribution is when the reactor coolant pumps are tripped when the vessel mixture is highly voided. After the pump performance has degraded enough that the flow pressure drop contribution to the vessel differential pressure is small, the change in RVLIS indication is very small when the pumps are tripped. As discussed in the summary report, the approach to ICC would be indicated when the wide range indication read 33 percent. If the pumps were tripped at this time, the core would still be covered. The operator knows that the core may uncover if the pumps were tripped with a wide range indication lower than 33 percent. Prior to pump trip, the core will remain adequately cooled due to forced circulation of the mixture. When the pumps trip, the two-phase level may equilibrate at a level below the top of the core. The narrow range indication provides an indication of core coolability at this time.

A Westinghouse RVLIS was installed at the Semiscale Test Facility in Idaho. Small break loss-of-coolant experiments were conducted at this facility by EG&G for the NRC. The results of these tests have been used to compare the RVLIS measurements with Semiscale differential pressure measurements, gamma densitometer data, and core cladding surface thermocouple indications. To date, after correcting for difference between PWR reactor vessel internals and Semiscale modeling, good correlation between Semiscale level indications and RVLIS measurements has been observed. In cooperation with the NRC, EG&G, and ORNL, Westinghouse has prepared a report summarizing the RVLIS performance during selected Semiscale tests. The reports are "Westinghouse Evaluation of RVLIS Performance at the Semiscale Test Facility for Test 5-2B-1," transmitted to the NRC in letter SED-SA-00081 dated June 28, 1982 from E.P. Rahe, Westinghouse, to L.E. Phillips, NRC, and "Westinghouse Evaluation of RVLIS Performance at the Semiscale Test Facility," transmitted to the NRC in letter NS-EPR-2526 dated December 9, 1981 from E.P. Rahe, Westinghouse, to L.E. Phillips, NRC.

3. Additional testing of the equipment described above has been completed in order to establish and upgrade qualification of the equipment to comply with NUREG-0737.

   The test programs were:

   a. Qualification tests of core exit thermocouples

   b. Qualification tests of reference (temperature compensation) junction boxes

   c. Qualification tests of electronics to add to the system computer and technical support center isolators and signal processing equipment.

   d. Qualification of isolation devices, cables and connectors, reference leg RTDs and hydraulic isolators.

   The in-service life of the RVLIS and T/CCM electronics is dependent upon proper maintenance, including the replacement of individual component parts when necessary. The provisions for this maintenance are included in the technical manual. Based on the assumption of normal conditions and proper maintenance of the components, the only limitation to the in-service life is the availability of replacement parts. It is estimated that in 20 years, some of the components will be technically obsolete and no longer produced. Consequently, the cards may have to be modified in the future to accommodate the current technology. Thus, any individual component failures are regarded as maintenance considerations, and their replacement is necessary to prolong in-service life.

   In-service life, which is different than design life and qualified life, is dependent upon implementing a scheduled preventative maintenance program including periodic overhaul of the equipment. In this manner, the equipment is restored to a level that ensures continual operability. In developing the maintenance program, repair costs may necessitate replacement of the equipment. If the maintenance program is followed, there is no apparent reason that operation of the equipment cannot be extended. Some of the equipment is similar to equipment installed in present Westinghouse plants that have been operating for 10 to 15 years.

The RVLIS valves supplied by Westinghouse were designed for a service life of 40 years.

4. An evaluation of the conformance of the reactor vessel level instrumentation system to NUREG-0737 is provided in Reference 7.

   An evaluation of the conformance of the thermocouple/core cooling monitor system to NUREG-0737 (Attachment l and Appendix B) is as follows:

   a. Attachment l, Item (1)

      The core exit thermocouples have been qualified so as to comply with the recommendations of Regulatory Guides 1.89 and 1.100. The thermocouples are located at the core exit and in an arrangement such that each of the redundant systems has core exit temperatures distributed over the entire core, in sufficient number to determine the radial power distribution and so located as to verify power distribution symmetry among core quadrants.

   b. Attachment 1, Item (2)

      The primary operator display is a computer-based display and calculation system. It provides information as required by subitems (a) through (f) of Attachment 1, Item (2) in Section 18.2.13.1.

   c. Attachment 1, Item (3)

      The backup system to display thermocouple readings is located in a cabinet which also houses the core cooling monitor. Backup system display is accomplished by the Class 1E ICC instrumentation including the ALS platform, flat panel displays, analog meters, and digital recorders. This backup system can display all of the 47 individual thermocouple temperatures within 6 minutes. The range extends from less than 200°F to 2300°F.

d. Attachment 1, Item (4)

Human factors consideration of the types and locations of displays and alarms is discussed in Sections 18.1.16 and 18.3.2. The ICC instrumentation has been considered in the overall human factors evaluation.

e. Attachment 1, Item (5)

Conformance to the specific items of Appendix B to NUREG-0737 is as follows:

1) Appendix B, Item (1)

The thermocouple/core cooling monitor instrumentation has been tested to establish environmental qualification in accordance with Regulatory Guide 1.89 (NUREG-0588). This qualification requirement applies to the complete instrumentation channel from thermocouple to display where display indicates the remote display, analog meter, and digital recorder. Qualified channel isolation devices isolate this qualified instrumentation from the data links, technical support center display, and plant computer display.

The seismic portion of the environmental qualification testing has been performed to comply with Regulatory Guide 1.100. This seismic qualification provides assurance that the instrumentation will continue to read within the required accuracy following, but not necessarily during, a safe shutdown earthquake.

Instrumentation whose ranges are required to extend beyond those ranges calculated in the most severe design basis accident event for a given variable has been qualified using the following criteria.

The qualification environment is based on the design basis accident events, except the assumed maximum of the value of the monitored variable is the value equal to the maximum range for the variable. The monitored variable is assumed to approach this peak by extrapolating the most severe initial ramp associated with the design basis accident events. The decay for this variable is considered proportional to the decay for this variable associated with the design basis accident events. No additional qualification margin needs to be added to the extended range variable. All environmental envelopes except that pertaining to the variable measured by the information display channel are those associated with the design basis accident events.

The above environmental qualification requirement does not account for steady-state elevated levels that may occur in other environmental parameters associated with the extended range variables. For example, a sensor measuring containment pressure must be qualified for the measured process variable range, but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for design basis accident events analyzed in Chapter 15.0. The extended range requirement ensures that the equipment will continue to provide information should conditions degrade beyond those postulated in the safety analysis. Since variable ranges are nonmechanistically determined, extension of associated parameter levels is not justifiable and has, therefore, not been required.

2) Appendix B, Item (2)

The purpose for qualifying the thermocouple/ core cooling monitoring system is to generate evidence that the equipment will maintain and perform its functions during a design basis event. It is of special concern during the qualification effort to uncover common mode failures.

The single-failure criteria for the computer and information beyond the isolator does not apply to this data-based information device as referred to in NUREG-0737 (clarification item [8]). In relation to diversification, the use of reactor vessel level instrumentation adds diversification to the ICC instrumentation. Inclusion of the core cooling (Tsat margin) monitoring functions enhances even further the capability of the ICC instrumentation.

3) Appendix B, Item (3)

The instrumentation is energized from Class 1E power sources.

4) Appendix B, Item (4)

Although not specifically recommended by NUREG-0737, the ICC instrumentation complies with the applicable portions of IEEE Standard 279. The systems utilize two trains; therefore, the "Exemption" as defined in Paragraph 4.11 of IEEE Standard 279 is applicable here.

5) Appendix B, Item (5)

The ICC equipment falls under the quality assurance requirements applicable to Class 1E equipment. Refer to Appendix 3A for a discussion of the quality assurance regulatory guides.

6) Appendix B, Item (6)

A flat panel display is provided for thermocouple readings in the backup system.

The computer-based (primary) thermocouple indication system has continuous (recording) displays.

7) Appendix B, Item (7)

The backup Class 1E system (which is on demand) includes redundant digital recorders. The computer-based (primary) indication system has continuous (recording) displays.

8) Appendix B, Item (8)

The instruments are specifically identified on the control panels so that the operator can easily discern that they are intended for use under accident conditions.

9) Appendix B, Item (9)

The WCGS ICC instrumentation complies with isolation requirements.

10) Appendix B, Item (10)

The WCGS ICC instrumentation is testable as required.

11) Appendix B, Item (11)

Servicing, testing, and calibrating programs are specified to maintain the capability of the monitoring instrumentation.

12) Appendix B, Item (12)

The access to the thermocouple/core cooling monitor permits removing channels for service (location is in the main control room). The testing and/or maintenance is facilitated by this system location.

13) Appendix B, Item (13)

The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

14) Appendix B, Item (14)

The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications potentially confusing to the operator.

15) Appendix B, Item (15)

The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

16) Appendix B, Item (16)

The instrumentation used in both the reactor vessel level instrumentation system and thermocouple monitoring receives input signals directly from the sensors that measure the parameters. The core cooling monitor also derives most of the signals directly from the sensors except in the case where Tsat pressures and others are obtained from the protection set.

17) Appendix B, Item (17)

The instruments used for ICC instrumentation are also used, with the exception of the reactor vessel level indication, for monitoring normal operation of the plant to the extent that it is practical. No loss of sensitivity is expected due to this use.

18) Appendix B, Item (18)

Periodic testing is in accordance with the applicable portions of Regulatory Guide 1.118.

(f) Attachment 1, Item (6)

The instrumentation system power supplies are in conformance with this requirement. However, the required circuits to the thermocouples are separated only to the maximum extent possible.

(g) Attachment 1, Item (7)

The instrumentation qualification is discussed in item 4.e.1 above.

(h) Attachment 1, Item (8)

The instrumentation system is in conformance with this requirement.

(i) Attachment 1, Item (9)

Quality assurance is discussed in item 4.e.5 above.

5. The nonredundant plant computer performs the thermocouple and Tsat functions for the primary display. However, these functions are also performed independent of the plant computer by the Class 1E ICC instrumentation. The Class 1E ALS platform performs the calculations and provides the signals to the Class 1E backup display.

6. In general, the system electronics are verified, maintained, and calibrated on-line by placing one of the redundant trains into a test and calibrate mode while leaving the other train in operation to monitor inadequate core cooling.

   A general verification was performed before shipment, but plant specific data was not used. The capability exists for the operator to verify the operation of the system. This involves disconnecting the sensors at the RVLIS electronics, providing an artificial input, and observing the response of the system on the front panel and remote display.

   The "7300" RVLIS incorporates circuit cards that provide an output proportional to the change in resistance of the RTD. The card contains a resistance bridge driven by a power supply to produce a signal proportional to the changes in resistance of the RTD, and a signal characterizer which accommodates linear calibration of non-linear RTDs.

   On-line calibration of the system is made possible by the "card edge" adjustments. The circuit cards were calibrated at the factory; however, if the function is changed or a component on the card is replaced, the calibration procedure is given within the equipment reference manual.

The RVLIS system requires the normal maintenance given to other control and protection systems within the plant. On-line maintenance is accomplished by placing only one of the two redundant trains into maintenance at a time; this allows continued monitoring of inadequate core cooling.

The remote display unit of RVLIS indicates the status of the input sensors. If any sensors are out of range, regardless of the reason, a symbol allows the affected level reading on the summary display page. The particular sensor that is out of range is identified at the bottom of the summary display page. Due to the redundant sensors and trains it is possible for the operator to disable some of the sensors without affecting the system reliability. The display indicates which level readings are affected. The disabled sensors are also displayed at the bottom of the summary page. A separate sensor status page can be displayed, showing all sensors that are disabled or out of range and their affected level readings.

In addition, software programs are provided so that the front panel controls and display can be used to perform a functional test, serial data link tests, calibration tests, and deadman timer tests. These tests are considered part of the operator maintenance procedures and are performed monthly. The cabinet-mounted equipment is designed to facilitate periodic tests to identify malfunctioning components and to ensure that the equipment functional operability is maintained comparable to the original design standards. Component power supply failure is annunciated in the main control room. The ICC instrumentation was installed by fuel load.

7. and 8. The Westinghouse Owners Group has developed ICC operating guidelines. These guidelines were developed using the generic ICC analyses discussed in Section 18.1.8. These generic guidelines were considered, as appropriate, by The Operating Agent in developing plant specific operating procedures.

9. No additional submittals are required, with the exception of emergency operating procedures.

18.2.13.3 Conclusion

The WCGS instrumentation used for detection of ICC adequately meets the guidance of NUREG-0737, Item II.F.2.

18.2.14 EMERGENCY POWER FOR PRESSURIZER EQUIPMENT (II.G.1)

18.2.14.1 NRC Guidance Per NUREG-0737

Position

Consistent with satisfying the requirements for General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10 CFR Part 50 for the event of loss-of-offsite power, the following positions shall be implemented:

Power Supply for Pressurizer Relief and Block Valves and Pressurizer Level Indicators

1. Motive and control components of the power-operated relief valves (PORVs) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

2. Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

3. Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.

4. The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

Clarification

1. Although the primary concern resulting from lessons learned from the accident at TMI is that the PORV block valves must be closable, the design should retain, to the extent practical, the capability to also open these valves.

2. The motive and control power for the block-valve should be supplied from an emergency power bus different from the source supplying the PORV.

3. Any changeover of the PORV and block-valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.

4. For those designs in which instrument air is needed for operation, the electrical power supply should be required to have the capability to be manually connected to the emergency power sources.

18.2.14.2 The Operating Agent Response

The pressurizer level indication channels are powered from vital, Class lE buses and displayed in the control room. These buses are described in Section 8.3; they are capable of being supplied from onsite emergency power (diesel generators) or offsite power.

The pressurizer PORVs and block valves are powered from vital, Class lE power sources. The separation group assignment is indicated on system drawings in Section 5.1.

The pressurizer PORVs are relied on to perform two safety functions:

a. Pressure control during a shutdown concurrent with loss of offsite power

b. Over-pressure protection at low reactor coolant system pressures

These functions are described in Sections 5.2 and 5.4 (A).

The PORV block valve is provided to isolate the PORV should the PORV develop unacceptable leakage during operation.

The pressurizer level indication is used during normal operation to control pressurizer level (see Figure 7.2-1, sheet 11).

The pressurizer level indication is used for the reactor trip logic and is a displayed parameter for post-accident and post-fire safe shutdown control. The safety design basis of the pressurizer level indication is provided in Section 7.2 and Section 7.5.

18.2.14.3 Conclusion

The WCGS design for the emergency power for pressurizer equipment satisfies Item II.G.1 of NUREG-0737. The WCGS design proposes an alternative to the power supply assignment proposed for the pressurizer PORVs and PORV block valves. The alternative is justified based on the diversity in power supply assignments for these valves, i.e., motor-operated (AC) block valves and solenoid-operated (DC) PORVs and based on the requirements for PORV use for overpressure protection.

18.2.15 REQUESTS BY NRC INSPECTION AND ENFORCEMENT BULLETINS (II.K.1)

18.2.15.1 NRC Guidance Per NUREG-0694

Position

"(C.1.5) Review all valve positions, positioning requirements, positive controls and related test and maintenance procedures to assure proper ESF functioning. See Bulletins 79-06A Item 8, 79-06B Item 7, and 79-08 Item 6 in Reference 11 [NUREG-0560].

(C.1.10) Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known. See Bulletins 79-05A Item 10, 79-06A Item 10, 79-06B Item 9, and 79-08 Item 8 in Reference 11 [NUREG-0560].

(C.1.17) For Westinghouse-designed reactors, trip the pressurizer low-level coincident signal bistables, so that safety injection would be initiated when the pressurizer low-pressure setpoint is reached regardless of the pressurizer level. See Bulletin 79-06A and Revision 1, Item 3 in Reference 11 [NUREG-0560]."

18.2.15.2 The Operating Agent Response

The development and review of procedures for testing, maintenance and system operation for the SNUPPS facilities were carried out as a joint effort between Union Electric, the Operating Agent, and other consultants. This development and review effort has considered the concerns of Items C.1.5 and C.1.10 of NUREG-0694 and The Operating Agent has performed the actions required by the applicable I&E Bulletin sections.

The item related to the safety injection logic is not applicable to the WCGS design (see Figure 7.2-1, Sheet 8).

18.2.15.3 Conclusion

The Operating Agent has developed and reviewed plant procedures in accordance with the NRC guidance in II.K.1 of NUREG-0694.

18.2.16 ORDERS ON FACILITIES WITH BABCOCK & WILCOX NUCLEAR STEAM SUPPLIER SYSTEMS (II.K.2)

18.2.16.1 Control of Auxiliary Feedwater Independent of the Integrated Control System (II.K.2.2)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.2 Auxiliary Feedwater System Upgrading (II.K.2.8)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.3 Failure Mode Effects Analysis on the Integrated Control System II.K.2.9)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.4 Safety-Grade Anticipatory Reactor Trip (II.K.2.10)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.5 Thermal Mechanical Report--Effect of High-Pressure Injection on Vessel Integrity for Small-Break Loss-of-Coolant Accident with no Auxiliary Feedwater (II.K.2.13)

18.2.16.5.1 NRC Guidance Per NUREG-0737

Position

A detailed analysis shall be performed of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater.

Clarification

The position deals with the potential for thermal shock of reactor vessels resulting from cold safety injection flow. One aspect that bears heavily on the effects of safety injection flow is the mixing of safety injection water with reactor coolant in the reactor vessel. B&W provided a report on July 30, 1980 that discussed the mixing question and the basis for a conservative analysis of the potential for thermal shock to the reactor vessel. Other PWR vendors are also required to address this issue with regard to recovery from small breaks with an extended loss of all feedwater. In particular, demonstration shall be provided that sufficient mixing would occur of the cold high-pressure injection (HPI) water with reactor coolant so that significant thermal shock effects to the vessel are precluded.

18.2.16.5.2 The Operating Agent Response

Westinghouse (in support of the Westinghouse Owners Group) has developed a method and performed analyses for a spectrum of small break loss-of-coolant accidents. The method employs the NOTRUMP computer program to generate the thermal/hydraulic transients. The thermal transients on the reactor vessel belt-line and the inlet nozzle are analyzed based on the thermal/hydraulic data from the NOTRUMP code. The Westinghouse-developed pressurized thermal shock evaluation (PTS) methodology has been submitted to the NRC (Reference 13). In accordance with the Operating Agent's letter to the NRC dated January 23, 1986, the WCGS calculated RTPTS values are well below the screening criterion of 10 CFR 50.61.

18.2.16.6 Effects of Slug Flow on Steam Generator Tubes (II.K.2.15)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.7 Reactor Coolant Pump Seal Damage (II.K.2.16)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.8 Potential for Voiding in the Reactor Coolant System During Transients (II.K.2.17)

18.2.16.8.1 NRC Guidance Per NUREG-0737

Position

Analyze the potential for voiding in the reactor coolant system (RCS) during anticipated transients.

Clarification

The background for this concern and a request for this analysis was originally sent to the Babcock and Wilcox (B&W) licensees in a letter from R. W. Reid, NRC, to all B&W operating plants, dated January 9, 1980.

18.2.16.8.2 The Operating Agent Response

Westinghouse (in support of the Westinghouse Owners Group) has performed a study which addresses the potential for void formation in Westinghouse-designed nuclear steam supply systems during natural circulation cooldown/depressurization transients. This study has been submitted to the NRC by the Westinghouse Owners Group (Ref. 1) and is applicable to Wolf Creek.

In addition, the Westinghouse Owners Group has developed appropriate modifications to the Westinghouse Owners Group Emergency Response Guidelines (ERGs) to take the results of the study into account so as to preclude void formation in the upper head region during natural circulation cooldown/depressurization transients, and to specify those conditions under which upper head voiding may occur. The Operating Agent has considered the generic guidance developed by the Westinghouse Owners Group in the development of plant specific operating procedures.

18.2.16.9 Sequential Auxiliary Feedwater Flow Analysis (II.K.2.19)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.10 Small-Break Loss-of-Coolant Accident Which Repressurizes the Reactor Coolant System to the Power-Operated Relief Valve Set Point (II.K.2.20)

Not applicable to Westinghouse pressurized water reactors.

18.2.17 RECOMMENDATIONS FROM THE BULLETINS AND ORDERS TASK FORCE (II.K.3)

18.2.17.1 Installation and Testing of Automatic Power-Operated Relief Valve Isolation System (II.K.3.1)

18.2.17.1.1 NRC Guidance Per NUREG-0737

Position

All PWR licensees should provide a system that uses the PORV block valve to protect against a small-break loss-of-coolant accident. This system will automatically cause the block valve to close when the reactor coolant system pressure decays after the PORV has opened. Justification should be provided to ensure that failure of this system would not decrease overall safety by aggravating plant transients and accidents.

Each licensee shall perform a confirmatory test of the automatic block valve closure system following installation.

Clarification

Implementation of this action item was modified in the May 1980 version of NUREG-0660. The change delays implementation of this action item until after the studies specified in TMI Action Plan item II.K.3.2 have been completed, if such studies confirm that the subject system is necessary.

18.2.17.1.2 The Operating Agent Response

Westinghouse, as a part of the response prepared for the Westinghouse Owners Group to address item II.K.3.2 (refer to Section 18.2.17.2), has evaluated the necessity of incorporating an automatic pressurizer power-operated relief valve isolation system. This evaluation is documented in Reference 2 and concluded that such a system should not be required. However, an automatic PORV isolation capability is part of the WCGS design as discussed in Sections 7.6.6 and 7.6.10.

18.2.17.1.3 Conclusion

Based on the above discussion, WCGS meets the guidelines of NUREG-0737, Item II.K.3.1.

18.2.17.2 Report on Overall Safety Effect of Power-Operated Relief Valve Isolation System (II.K.3.2)

18.2.17.2.1 NRC Guidance Per NUREG-0737

Position

1. The licensee should submit a report for staff review documenting the various actions taken to decrease the probability of a small-break loss-of-coolant accident (LOCA) caused by a stuck-open, power-operated relief valve (PORV) and show how those actions constitute sufficient improvements in reactor safety.

2. Safety-valve failure rates based on past history of the operating plants designed by the specific nuclear steam supply system (NSSS) vendor should be included in the report submitted in response to (1) above.

Clarification

Based on its review of feedwater transients and small LOCAs for operating plants, the Bulletins and Orders Task Force in the Office of Nuclear Reactor Regulation recommended that a report be prepared and submitted for staff review which documents the various actions that have been taken to reduce the probability of a small-break LOCA caused by a stuck-open PORV and show how these actions constitute sufficient improvements in reactor safety. Action Item II.K.3.2 of NUREG-0660, published in May 1980, changed the implementation of this recommendation as follows: In addition to modifications already implemented on PORVs, the report specified above should include safety examination of an automatic PORV isolation system identified in Task Action Plan item II.K.3.1.

Modifications to reduce the likelihood of a stuck-open PORV will be considered sufficient improvements in reactor safety if they reduce the probability of a small-break LOCA caused by a stuck-open PORV such that it is not a significant contributor to the probability of a small-break LOCA due to all causes. (According to WASH-1400, the median probability of a small-break LOCA S2 with a break diameter between 0.5 inches and 2.0 inches is 10^{-3} per reactor-year with a variation ranging from 10^{-2} to 10^{-4} per reactor-year.)

The above-specified report should also include an analysis of safety-valve failures based on the operating experience of the pressurized-water-reactor (PWR) vendor designs. The licensee has the option of preparing and submitting either a plant-specific or a generic report. If a generic report is submitted, each licensee should document the applicability of the generic report to his own plant.

Based on the above guidance and clarification, each licensee should perform an analysis of the probability of a small-break LOCA caused by a stuck-open PORV or safety valve. This analysis should consider modifications which have been made since the TMI-2 accident to improve the probability. This analysis shall evaluate the effect of an automatic PORV isolation system specified in Task Action Plan, Item II.K.3.1.

In evaluating the automatic PORV isolation system, the potential of causing a subsequent stuck-open safety valve and the overall effect on safety (e.g., effect on other accidents) should be examined.

Actual operational data may be used in this analysis, where appropriate. The bases for any assumptions used should be clearly stated and justified.

The results of the probability analysis should then be used to determine whether the modifications already implemented have reduced the probability of a small-break LOCA due to a stuck-open PORV or safety valve a sufficient amount to satisfy the criterion stated above, or whether the automatic PORV isolation system specified in Task Action item II.K.3.1 is necessary.

In addition to the analysis described above, the licensee should compile operational data regarding pressurizer safety valves for PWR vendor designs. These data should then be used to determine safety-valve failure rates.

The analyses should be documented in a report. If this requirement is implemented on a generic basis, each licensee should review the appropriate generic report and document its applicability to his own plant(s). The report and the documentation of applicability (where appropriate) should be submitted for NRC staff review by the specified date.

18.2.17.2.2 The Operating Agent Response

As mentioned in item II.K.3.1 above (Section 18.2.17.1), the Westinghouse Owners Group has submitted a Westinghouse-prepared report (Ref. 2) which provides a probabilistic analysis to determine the probability of a PORV LOCA, estimates the effect of the post-TMI modifications, evaluates an automatic PORV isolation concept, and provides PORV and safety valve operational data for Westinghouse plants. Because of the sensitivity analyses included in the report, the report is generic and is applicable to the WCGS. The report identifies a significant reduction in the PORV LOCA probability as a result of post-TMI modifications, and the calculations compare favorably with the operational data for Westinghouse plants (included as an appendix to the report).

18.2.17.2.3 Conclusion

The requirements of this item were resolved by submittal of the Reference 2 analysis report.

18.2.17.3 Reporting Safety and Relief Valve Failures and Challenges (II.K.3.3)

18.2.17.3.1 NRC Guidance Per NUREG-0694

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report.

18.2.17.3.2 The Operating Agent Response

The failure of a PORV to close on demand and a failure of a primary system safety valve to close will no longer be reported per the guidance of Generic Letter 97-02.

18.2.17.3.3 Conclusion

The Operating Agent's commitment documented above meets the requirements of NUREG-0737, II.K.3.3.

18.2.17.4 Automatic Trip of Reactor Coolant Pumps During Loss-of-Coolant Accident (II.K.3.5)

18.2.17.4.1 NRC Guidance Per NUREG-0737

Position

Tripping of the reactor coolant pumps in case of a loss-of-coolant accident (LOCA) is not an ideal solution. Licensees should consider other solutions to the small-break LOCA problem (for example, an increase in the safety injection flow rate). In the meantime, until a better solution is found, the reactor coolant pumps should be tripped automatically in case of a small-break LOCA. The signals designated to initiate the pump trip are discussed in NUREG-0623.

Clarification

This action item has been revised in the May 1980 version of NUREG-0660 to provide for continued study of criteria for early reactor coolant pump trip. Implementation, if any is required, will be delayed accordingly. As part of the continued study, all holders of approved emergency core cooling (ECC) models have been required to analyze the forthcoming LOFT test (L3-6). The capability of the industry models to correctly predict the experimental behavior of this test will have a strong input on the staff's determination of when and how the reactor coolant pumps should be tripped.

18.2.17.4.2 The Operating Agent Response

In response to IE Bulletin No. 79-06C, Westinghouse, in support of the Westinghouse Owners Group (WOG) performed an analysis of delayed reactor coolant pump (RCP) trip during small-break LOCAs. This analysis is documented in Reference 3 and is the basis for the Westinghouse and WCGS position on RCP trip (i.e., automatic RCP trip is not necessary since sufficient time is available for manual tripping of the RCPs).

Westinghouse (again in support of the Westinghouse Owners Group) has performed test predictions of the LOFT Experiment L3-6. The results of these predictions are documented in References 4 and 5. The results constitute both a best estimate model prediction with the NOTRUMP computer program and an evaluation model prediction with the WFLASH computer program, using the supplied set of initial boundary assumptions.

By letter dated February 8, 1983, the NRC issued Generic Letter 83-10c. The NRC concluded that each nuclear plant applicant should determine the need to trip the reactor coolant pumps following an accident or transient. By SNUPPS letters dated April 22, 1983 and April 13, 1984, responses to Generic Letter 83-10c were provided. The responses referenced previous Westinghouse Owner's Group reports dated December 1, 1983 and March 9, 1984.

The NRC has issued Generic Letter 85-12 which confirmed the acceptability of the information provided by the Westinghouse Owner's Group, in response to Generic Letter 83-10, and requested that plant-specific information be submitted to the NRC. By letter dated November 27, 1985, the Operating Agent responded to Generic Letter 85-12. By letter dated March 21, 1989 (89-00605), the NRC staff found that Wolf Creek appropriately referenced the WOG reports and the issue was closed.

18.2.17.5 Evaluation of PORV Opening Probability During Overpressure Transient (II.K.3.7)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.6 Proportional Integral Derivative Controller Modification (II.K.3.9)

18.2.17.6.1 NRC Guidance Per NUREG-0737

Position

The Westinghouse-recommended modification to the proportional integral derivative (PID) controller should be implemented by affected licensees.

Clarification

The Westinghouse-recommended modification is to raise the interlock bistable trip setting to preclude derivative action from opening the power-operated relief valve (PORV). Some plants have proposed changing the derivative action setting to zero, thereby eliminating it from consideration. Either modification is acceptable to the staff. This represents a newly available option.

18.2.17.6.2 The Operating Agent Response

The WCGS design includes a pressure integral derivative (PID) controller in the power-operated relief valve control circuit (see Figures 7.7-4 and 7.2-1, Sheet 11). The time derivative constant in the PID controller for the pressurizer PORV will be turned to "OFF" (set to zero) at WCGS. The appropriate plant procedure for calibrating the set points in this nonsafety grade system will reflect this decision.

Setting the derivative time constant to "OFF," in effect, removes the derivative action from the controller. Removal of the derivative action will decrease the likelihood of opening the pressurizer PORV since the actuation signal for the valve is then no longer sensitive to the rate of change of pressurizer pressure.

18.2.17.6.3 Conclusion

The NUREG-0737 provisions for the PID controller are met at WCGS.

18.2.17.7 Proposed Anticipatory Trip Modification (II.K.3.10)

18.2.17.7.1 NRC Guidance Per NUREG-0737

Position

The anticipatory trip modification proposed by some licensees to confine the range of use to high-power levels should not be made until it has been shown on a plant-by-plant basis that the probability of a small-break loss-of-coolant accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification.

Clarification

This evaluation is required for only those licensees/applicants who propose the modification.

18.2.17.7.2 The Operating Agent Response

This anticipatory trip modification is included in the WCGS design.

The NRC has raised the question of whether the pressurizer power-operated relief valves would be actuated for a turbine trip without reactor trip below a power level of 50 percent (P-9 set point). An analysis has been performed using realistic yet conservative values for the core physics parameters (primarily reactivity feedback coefficients and control rod worths), and a conservatively high initial power, average reactor temperature (TAVG), and pressurizer pressure level to account for instrument inaccuracies.

The transient was initiated from the set point for the P-9 interlock, namely 50 percent of the reactor full power level plus 2 percent for power measurement uncertainty. This is a conservative starting point, and would bracket all transients initiated from a lower power level. The core physics parameters used were the ones that would result in the most positive reactivity feedbacks (i.e., highest power levels). The steam dump valves were assumed to be actuated by the load rejection controller.

Based upon the results from the analysis, the peak pressure reached in the pressurizer would be 2,302 psia. The set point for the actuation of the pressurizer power-operated relief valves is 2,350 psia. Even including the +20 psi pressure measurement uncertainty, there is still a margin of 28 psi between the peak pressure reached and the minimum activation pressure for the pressurizer power-operated relief valves.

An additional analysis has been performed to determine the consequences (specifically the likelihood of the pressurizer power-operated relief valves opening) of having a turbine trip due to a loss of condenser vacuum.

The major difference between this analysis and the one presented above is that now the normal steam dump system is unavailable, and the steam relief must be carried out through the atmospheric relief valves. Since there is a longer delay time before the atmospheric reliefs reach their set point (in comparison to the normal steam dump system) and their capacity is about one-half of the steam dump system, there is an increased likelihood that the pressurizer PORVs will open.

Figure 18.2-14 shows the plant operating ranges for which the pressurizer PORVs will open for a turbine trip due to a loss of condenser signal. Above 50 percent power, a turbine trip will cause a reactor trip (due to P-9 set point), and the pressurizer PORV set point will not be reached. Below a power level of 35 to 40 percent (depending on fuel burnup), the pressurizer spray rate is adequate to maintain the pressurizer pressure below the set point. Therefore, only in the narrow band between about 35 and 50 percent power will the pressurizer PORVs open for a loss of condenser.

Based upon the operating history of current plants, the chances of getting a condenser unavailable signal (and hence a turbine trip) is about 156 out of 10^7 operating hours. Assuming 98 percent plant availability and a 40-year plant lifetime, this works out to about four condenser unavailable turbine trips occurring during the normal life of a plant. Assuming an equal chance of having the plant operate anywhere between 0 and 100 percent power (an unrealistic value, since they usually operate either at a full or no load level), the chances of having a condenser unavailable signal generate a transient which would result in the opening of the pressurizer PORVs is less than one per plant lifetime.

18.2.17.7.3 Conclusion

The analysis described above demonstrates an acceptably low probability of a small LOCA caused by a stuck open PORV.

18.2.17.8 <u>Justification for Use of Certain PORVs (II.K.3.11)</u>

18.2.17.8.1 NRC Guidance Per NUREG-0694

Position

Demonstrate that the PORV installed in the plant has a failure rate equivalent to or less than the valves for which there is an operating history.

18.2.17.8.2 The Operating Agent Response

The PORVs to be used in the WCGS design are pilot-operated relief valves. These valves are a new design and were supplied by Garrett. The valve design was tested in the Electric Power Research Institute (EPRI) valve test program (refer to NUREG-0737, Item II.D.1). The performance of the Garrett PORVs was comparable to other designs tested. In addition, the analysis of PORVs in accordance with NUREG-0737, Item III.K.3.2 (Section 18.2.17.2) addresses valve failure rates.

18.2.17.8.3 Conclusion

Based on the EPRI testing and PORV analysis identified above, failure rates for the WCGS PORV design are adequately addressed.

18.2.17.9 <u>Confirm Existence of Anticipatory Reactor Trip Upon Turbine Trip (II.K.3.12)</u>

18.2.17.9.1 NRC Guidance Per NUREG-0737

Position

Licensees with Westinghouse-designed operating plants should confirm that their plants have an anticipatory reactor trip upon turbine trip. The licensee of any plant where this trip is not present should provide a conceptual design and evaluation for the installation of this trip.

18.2.17.9.2 The Operating Agent Response

The WCGS design includes an anticipatory reactor trip upon turbine trip (refer to Figure 7.2-1).

18.2.17.10 Separation of High-Pressure Coolant Injection and Reactor Core Isolation Cooling System Initiation Levels--Analysis and Implementation (II.K.3.13)

Not applicable to pressurized water reactors.

18.2.17.11 Isolation of Isolation Condensers on High Radiation (II.K.3.14)

Not applicable to pressurized water reactors.

18.2.17.12 Modify Break-Detection Logic to Prevent Spurious Isolation of High-Pressure Coolant Injection and Reactor Core Isolation Cooling (II.K.3.15)

Not applicable to pressurized water reactors.

18.2.17.13 Reduction of Challenges and Failures of Relief Valves--Feasibility Study and System Modification (II.K.3.16)

Not applicable to pressurized water reactors.

18.2.17.14 Report on Outages of Emergency Core-Cooling Systems Licensee Report and Proposed Technical Specification Changes (II.K.3.17)

18.2.17.14.1 NRC Guidance Per NUREG-0737

Position

Several components of the emergency core-cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Clarification

The present technical specifications contain limits on allowable outage times for ECC systems and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECC equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) cause of the outage; (3) ECC systems or components involved in the outage; and (4) corrective action taken. Test and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicant for an operating license shall establish a plan to meet these requirements.

18.2.17.14.2 The Operating Agent Response

The Operating Agent provides safety system outage information as required by regulations and WCGS Technical Specifications. In addition, records are retained of the maintenance, inspections, and surveillance tests of the principal items related to nuclear safety. These records can be reviewed by the NRC for additional specific data on component availability. The documentation will include: 1) outage dates and duration, 2) cause of the outage, 3) systems or components involved in the outage, and 4) corrective action taken.

18.2.17.14.3 Conclusion

The WCGS reports safety system outages as required by 10 CFR 50.72, 10 CFR 50.73, The Technical Specifications and other applicable regulations. This reporting ensures that the data requested by Item II.K.3.17 of NUREG-0737 is available.

18.2.17.15 Modification of Automatic Depressurization System Logic--Feasibility for Increased Diversity for Some Event Sequences (II.K.3.18)

Not applicable to pressurized water reactors.

18.2.17.16 Interlock on Recirculation Pump Loops (II.K.3.19)

Not applicable to pressurized water reactors.

18.2.17.17 Restart of Core Spray and Low-Pressure Coolant-Injection Systems (II.K.3.21)

Not applicable to pressurized water reactors.

18.2.17.18 Automatic Switchover of Reactor Core Isolation Cooling System Suction--Verify Procedures and Modify Design (II.K.3.22)

Not applicable to pressurized water reactors.

18.2.17.19 Confirm Adequacy of Space Cooling for High-Pressure Coolant Injection and Reactor Core Isolation Cooling Systems (II.K.3.24)

Not applicable to pressurized water reactors.

18.2.17.20 Effect of Loss of Alternating-Current Power on Pump Seals (II.K.3.25)

18.2.17.20.1 NRC Guidance Per NUREG-0737

Position

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating-current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

Clarification

The intent of this position is to prevent excessive loss of reactor coolant system (RCS) inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be loss of offsite power. If seal failure is the consequence of loss of cooling water to the reactor coolant pump (RCP) seal coolers for 2 hours, due to loss of offsite power, one acceptable solution would be to supply emergency power to the component cooling water pump. This topic is addressed for Babcock and Wilcox (B&W) reactors in Section II.K.2.16.

18.2.17.20.2 The Operating Agent Response

During normal operation, seal injection flow from the chemical and volume control system is provided to cool the RCP seals, and the component cooling water system provides flow to the thermal barrier heat exchanger to limit the heat transfer from the reactor coolant to the RCP internals. In the event of a loss of offsite power, the RCP motor is deenergized and both of these cooling supplies are terminated; however, the diesel generators are automatically started and both seal injection flow and component cooling water to the thermal barrier heat exchanger are automatically restored within seconds. Either of these cooling supplies is adequate to provide seal cooling and prevent seal failure due to a loss of seal cooling during a loss of offsite power for at least 2 hours.

18.2.17.20.3 Conclusion

The WCGS design meets the RCP seal cooling requirements of this item.

18.2.17.21 Provide Common Reference Level for Vessel Level Instrumentation (II.K.3.27)

Not applicable to pressurized water reactors.

18.2.17.22 Verify Qualification of Accumulators on Automatic Depressurization System Valves (II.K.3.28)

Not applicable to pressurized water reactors.

18.2.17.23 Study to Demonstrate Performance of Isolation Condensers with Noncondensibles (II.K.3.29)

Not applicable to pressurized water reactors.

18.2.17.24 Revised Small-Break Loss-of-Coolant Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K (II.K.3.30)

18.2.17.24.1 NRC Guidance Per NUREG-0737

Position

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR

Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

Clarification

As a result of the accident at TMI-2, the Bulletins and Orders Task Force was formed within the Office of Nuclear Reactor Regulation. This task force was charged, in part, to review the analytical predictions of feedwater transients and small-break LOCAs for the purpose of assuring the continued safe operation of all operating reactors, including a determination of acceptability of emergency guidelines for operators.

As a result of the task force reviews, a number of concerns were identified regarding the adequacy of certain features of small-break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each lightwater reactor (LWR) vendor's models, were documented in the task force reports for each LWR vendor. In addition to the modeling concerns identified, the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small-break LOCA model as required by II.4 of Appendix K to 10 CFR 50 was needed. This included providing predictions of Semiscale Test S-07-10B and LOFT Test (L3-1) and providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small-break LOCAs.

Based on the cumulative staff requirements for additional small-break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

The purpose of the verification was to provide the necessary assurance that the small-break LOCA models were acceptable to calculate the behavior and consequences of small primary system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small-break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.

The specific staff concerns regarding small-break LOCA models are provided in the analysis sections of the B&O Task Force reports for each LWR vendor, (NUREG-0635, -0565, -0626, -0611, and

-0623). These concerns should be reviewed in total by each holder of an approved emergency core cooling system (ECCS) model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small-break test series and LOFT Tests (L3-1) and (L3-2). The staff believes that the present small-break LOCA models can be both qualitatively and quantitatively assessed against these tests. Other separate effects tests (e.g., ORNL core uncovery tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify (1) which areas of the models, if any, the licensee intends to upgrade, (2) which areas the licensee intends to address by further justification of acceptability, (3) test data to be used as part of the overall verification/upgrade effort, and (4) the estimated schedule for performing the necessary work and submitting this information for staff review and approval.

18.2.17.24.2 The Operating Agent Response

The present Westinghouse Small Break Evaluation Model used to analyze WCGS (refer to Section 15.6.5) is in conformance with 10 CFR Part 50, Appendix K. Nevertheless, Westinghouse (as documented in Ref. 6) has addressed the specific NRC items contained in NUREG-0611 in a model (NOTRUMP) documented in WCAP 10054 (dated 12/28/82) and WCAP 10079 (dated 11/12/82). The NRC approved NOTRUMP as satisfying II.K.3.30 in a safety evaluation dated May 21, 1985. NOTRUMP was also found to be in full compliance with Appendix K to 10 CFR 50 and was designated as the new Westinghouse licensing tool for small-break LOCA evaluations to satisfy the provisions of II.K.3.31.

18.2.17.24.3 Conclusion

The NOTRUMP Code satisfies the provisions of NUREG-0737, Item II.K.3.30.

18.2.17.25 Plant-Specific Calculations to Show Compliance With 10 CFR Part 50.46 (II.K.3.31)

18.2.17.25.1 NRC Guidance Per NUREG-0737

Position

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs), as described in item

II.K.3.30 to show compliance with 10 CFR 50.46, should be submitted for NRC approval by all licensees.

18.2.17.25.2 The Operating Agent Response

The present Westinghouse Small Break Evaluation Model and small break LOCA analyses for WCGS (refer to Section 15.6.5) are in conformance with 10 CFR Part 50, Appendix K and 10 CFR Part 50.46. As stated in the response to Item II.K.3.30 (refer to Section 18.2.17.24.2), the NRC has approved the Westinghouse NOTRUMP Code for small-break LOCA analysis.

In response to generic letter 83-35, the Westinghouse Owners Group has developed a program to demonstrate on a generic basis that the new NOTRUMP model predicts lower calculated peak clad temperatures than WFLASH. By letter dated October 6, 1986 (Reference 17), the NRC concluded that the generic study results could be used to resolve NUREG-0737, Item II.K.3.31. The Operating Agent has submitted a letter dated June 26, 1986 to the NRC to verify the applicability of the generic study results to WCGS.

18.2.17.25.3 Conclusion

Upon submittal of the letter confirming the applicability of the generic results to WCGS, the requirements of NUREG-0737, Item II.K.3.31 are met.

18.2.17.26 <u>Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure (II.K.3.44)</u>

Not applicable to pressurized water reactors.

18.2.17.27 <u>Evaluation of Depressurization with Other than Automatic Depressurization System (II.K.3.45)</u>

Not applicable to pressurized water reactors.

18.2.17.28 <u>Identify Water Sources Prior to Actuation of Automatic Depressurization System (II.K.3.57)</u>

Not applicable to pressurized water reactors.

18.2.18 REFERENCES

1. Letter OG-57, dated April 20, 1981, Jurgensen, R. W. (Chairman, Westinghouse Owners Group) to Check, P. S. (NRC).

2. Wood, D. C. and Gottshall, C. L., "Probabilistic Analysis and Operational Data in Response to NUREG-0737 Item II.K.3.2 for Westinghouse NSSS Plants," WCAP-9804, February 1981.

3. "Analysis of Delayed Reactor Coolant Pump Trip During Small Loss of Coolant Accidents for Westinghouse Nuclear Steam Supply Systems," WCAP-9584 (Proprietary) and WCAP-9585 (Non-Proprietary), August 1979.

4. Letter OG-49, dated March 3, 1981, Jurgensen, R. W. (Chairman, Westinghouse Owners Group) to Ross, D. F., Jr. (NRC).

5. Letter OG-50, dated March 23, 1981, Jurgensen, R. W. (Chairman, Westinghouse Owners Group) to Ross, D. F., Jr. (NRC).

6. Letter NS-TMA-2318, dated September 26, 1980, Anderson, T. M. (Westinghouse) to Eisenhut, D. G. (NRC).

7. Letter NS-TMA-2357, dated December 23, 1980, T. M. Anderson (Westinghouse) to D. G. Eisenhut (NRC).

8. Rockwell, T., Reactor Shielding Design Manual, D. Van Nostrand Co., New York, New York, 1956.

9. QAD-CG: A Combinatorial Geometry Version of QAD-P5A, Bechtel Power Corporation internal computer code.

10. Letter SLNRC 83-0048, dated September 1, 1983, N. A. Petrick (SNUPPS) to H. R. Denton (NRC).

11. Letter SLNRC 84-004, dated January 16, 1984, N. A. Petrick (SNUPPS) to H. R. Denton (NRC).

12. Letter SLNRC 83-002 (distributed as 82-002), dated January 7, 1983, N. A. Petrick (SNUPPS) to H. R. Denton (NRC).

13. "A Generic Assessment of Significant Flaw Extension, Including, Stagnant Loop Conditions, From Pressurized Thermal Shock of Reactor Vessels on Westinghouse Power Plants," WCAP 10319, December 1983.

14. Union Electric Calculation Sheet HPCI-84-04, dated April 27, 1984, "An Assessment of Personnel Dose to Obtain Gaseous Effluent and Reactor Coolant System Grab Samples Following a DBA Loss of Coolant Accident."

15. Letter NS-NRC-86-3099, dated February 20, 1986, Rahe, E. P. (Westinghouse) to Taylor, J. M. (NRC).

16. "Methodology for Qualifying Westinghouse WRD-Supplied NSSS Safety-Related Electrical Equipment," WCAP-8587, Rev. 6-A, dated November 1983.

17. Safety Evaluation Report, WCAP-11145, Westinghouse Small-Break LOCA ECCS Evaluation Model Generic Study with NOTRUMP Code, transmitted by NRC letter (C. Rossi) to Westinghouse Owners Group (L. Butterfield), dated October 6, 1986.

TABLE 18.2-1 (Page 1 of 2)

MITIGATING CORE DAMAGE COURSE

COURSE DESCRIPTION

Westinghouse has performed detailed analysis of numerous situations which could arise in two loop, three loop, and four loop PWR plants. The Westinghouse program has then been structured to use the most limiting case for each situation as the basis for instruction to students.

COURSE INTRODUCTION
- Major Plant Assumptions
- Core Thermal and Linear Power Density Limits

INCORE INSTRUMENTATION
- System Functions, Characteristics, and Operations Including Moveable Incore Detection System and Incore Thermocouples
- Determination of Core Damage Extent and Core Geometry Changes
- Determination of Peak Core Temperatures
- Methods of Obtaining Extended Range Readings
- Direct Readings at Terminal Junctions
- System Outputs and Recorders
- Potential Causes of Instrument Failures and Probable Time to Failure Under Various Degraded Conditions

EXCORE INSTRUMENTATION
- Factors Affecting Excore Instrumentation Response During Various Operational Conditions
- Expected Indications for Various Loss of Coolant Accidents
- Determination of Void Formation in the Core Region
- Detector Reliability Under Adverse Environmental Conditions

POST ACCIDENT CHEMISTRY
- Expected Changes in Primary Plant Chemistry
- Consequences of Transferring Primary Water Outside of Containment
- Long Term System Problems Associated with Extended Immersion in Contaminated Primary Water and Potential Failure Mechanisms
- Expected Isotopic Breakdowns for Various Conditions of Fuel and Cladding

RADIATION MONITORING

- Types of Detectors Utilized in the Radiation Monitoring System
- Response of Process and Area Monitors to Radioactivity Release
- Verification of Installed Instrumentation Through Supplemental Measurements
- Determination of Dose Rates with Nonfunctional or Nonavailable Instrumentation

VITAL PROCESS INSTRUMENTATION

- Specific Applications of Major Types of Transmitters
- Various Failure Methods and Their Reliability
- Pressurizer Pressure Instrumentation
- Steam Generator Level Instrumentation
- Various Temperature Detectors
- Major Flow Indicators
- Alternate Methods to Determine Critical Process Variables
- Use of Plant Computer Stored Information

GAS GENERATION

- Physical and Chemical Characteristics and Potential Sources of Major Gases
- Hydrogen Flammability and Explosion Limits
- Venting, Disposal, and Sampling Methods of Containment Gases

POTENTIALLY DAMAGING SITUATIONS AND COOLING METHODS

- Loss of Feedwater Induced Loss of Coolant Accident
- Heat Removal Paths and Sinks
- Steam and Water Cooling
- Injection Flowpaths - Hot Leg Versus Cold Leg Injection
- Quenching Effects on Clad Material
- Gas or Steam Binding Effects
- Natural Circulation Indications and Controls - One Phase and Two Phase Fluids

TABLE 18.2-2
ESSENTIAL/NONESSENTIAL CONTAINMENT PENETRATIONS

Fig. 6.2.4-1, Sheet	Penetration	Service	Essential/ Nonessential
1	P-1	Main steam/PORV	Nonessential/ essential
2	P-2	Main steam/PORV	Nonessential/ essential
3	P-3	Main steam/PORV & AFW steam	Nonessential/ essential
4	P-4	Main steam/PORV & AFW steam	Nonessential/ essential
5	P-5	Main/aux. feedwater	Nonessential/ essential
6	P-6	Main/aux. feedwater	Nonessential/ essential
7	P-7	Main/aux. feedwater	Nonessential/ essential
8	P-8	Main/aux. feedwater	Nonessential/ essential
9	P-9	SG blowdown	Nonessential
10	P-10	SG blowdown	Nonessential
11	P-11	SG blowdown	Nonessential
12	P-12	SG blowdown	Nonessential
13	P-13	Containment recirculation sump suction to containment spray pump	Essential
14	P-14	Containment recirculation sump suction to RHR pump	Essential
15	P-15	Containment recirculation sump suction to RHR pump	Essential
16	P-16	Containment recirculation sump suction to containment spray pump	Essential
17	P-21	RHR hot leg injection	Essential
18	P-22	RCP-B seal water supply	Essential
19	P-23	CVCS letdown	Nonessential
20	P-24	RCP seal water return	Nonessential

TABLE 18.2-2 (Sheet 2)

Fig. 6.2.4-1, Sheet	Penetration	Service	Essential/ Nonessential
21	P-25	Reactor makeup water supply	Nonessential
22	P-26	Reactor coolant drain tank discharge	Nonessential
23	P-27	RHR cold leg injection loops 3 and 4	Essential
24	P-28	ESW supply to containment air coolers	Essential
25	P-29	ESW return from containment air coolers	Essential
26	P-30	Instrument air supply	Nonessential
27	P-32	Containment sump pump discharge	Nonessential
28	P-34	Containment ILRT test line	Nonessential
29	P-39	RCP-C seal water supply	Essential
30	P-40	RCP-D seal water supply	Essential
31	P-41	RCP-A seal water supply	Essential
32	P-43	Auxiliary steam supply - decontamination	Nonessential
33	P-44	Reactor coolant drain tank vent	Nonessential
34	P-45	Accumulator nitrogen supply	Nonessential
35	P-48	SI pump-B, discharge to hot legs 1 and 4	Essential
36	P-49	SI pumps to cold legs 1, 2, 3, and 4	Essential
37	P-51	ILRT pressure sensing lines	Nonessential
38	P-52	RHR shutdown suction	Essential
39	P-53	Fuel pool cooling and cleanup, refueling pool supply	Nonessential
40	P-54	Fuel pool cooling and cleanup, refueling pool suction	Nonessential
41	P-55	Fuel pool cooling and cleanup, refueling pool skimmer suction	Nonessential

TABLE 18.2-2 (Sheet 3)

Fig. 6.2.4-1, Sheet	Penetration	Service	Essential/ Nonessential
42	P-56	Post-LOCA hydrogen analyzer return	Essential
42a	P-56	Containment Atmosphere Monitor	Nonessential
42b	P-57	Sample Return - Post Accident Sampling System	Nonessential
43	P-58	Accumulator fill line from SI pump	Nonessential
43a	P-59,91	RVLIS Sample Line Reactor Coolant System	Nonessential
44	P-62	Pressurizer relief tank nitrogen supply	Nonessential
45	P-63	Service air supply	Nonessential
45a	P-64	RC loop and Pressurizer liquid sample	Nonessential
46	P-65	Hydrogen purge	Nonessential
47	P-66	Containment spray supply pump B	Essential
48	P-67	Fire protection supply	Nonessential
49	P-69	Pressurizer vapor sample	Nonessential
50	P-71	ESW supply to containment air coolers	Essential
51	P-73	ESW return from containment air coolers	Essential
52	P-74	CCW supply	Essential
53	P-75	CCW return	Essential
54	P-76	CCW return RCP thermal barrier	Essential
55	P-78	S.G. drain	Nonessential
56	P-79	RHR shutdown suction	Essential
57	P-80	CVCS charging	Nonessential
58	P-82	RHR discharge to hot legs loops 1 and 2	Essential
59	P-83	S.G. D sample	Nonessential
60	P-84	S.G. A sample	Nonessential
61	P-85	S.G. B sample	Nonessential
62	P-86	S.G. C sample	Nonessential
63	P-87	SI pump A discharge to hot legs loops 2 and 3	Essential
64	P-88	Boron injection supply to cold legs loops 1, 2, 3, and 4	Essential
65	P-89	Containment spray supply pump A	Essential
66	P-92	ECCS test line return	Nonessential
67	P-93	R.C. loop liquid samples	Nonessential
68	P-95	Accumulator tank sample	Nonessential

TABLE 18.2-2 (Sheet 4)

Fig. 6.2.4-1, Sheet	Penetration	Service	Essential/ Nonessential
69	P-97	Post-LOCA hydrogen analyzer return	Essential
69a	P-97	Sample Return – Containment Atmosphere Monitor	Nonessential
69b	P-98	Breathing Air Supply	Nonessential
70	P-99	Post-LOCA hydrogen analyzer supply	Essential
70a	P-99	Sample Line - Containment Atmosphere Monitor	Nonessential
71	P-101	Post-LOCA hydrogen analyzer supply	Essential
71a	P-101	Sample Line - Containment Atmosphere Monitor	Nonessential
72	E-256 P-103/104	Containment pressure sensing monitors	Essential
73	V-160	Containment purge exhaust	Nonessential
74	V-161	Containment purge supply	Nonessential

TABLE 18.2-3

DETAILS FOR THE THERMOCOUPLE/CORE COOLING MONITOR SYSTEM

<u>Display</u>	
Information Displayed (T-Tsat, Tsat, Press, etc.)	P-Psat subcooled- T-Tsat - superheated
Display Type (analog, digital, CRT)	Analog (control board) and digital (electronics package)
Continuous or on Demand	Continuous (control board) and on demand (electronics package)
Single or Redundant Display	Redundant
Location of Display	Control board and control room
Alarms (include set points)	Caution: 5°F subcooled Alarm: 0°F subcooled
Overall uncertainty	Digital: 3°F for RTD Analog: 5°F for RTD
Range of Display	Calibrated: 200°F subcooled to 2000°F superheat Overall: Never off scale
Qualifications (seismic, environmental)	Seismic and environmental

TABLE 18.2-3 (Sheet 2)

Calculator

Type (process computer, dedicated digital or analog calc.)	Dedicated digital
If process computer is used specify availability (percent of time)	NA
Single or redundant calculators	Redundant
Selection Logic (highest T., lowest press)	Auctioneered high hot leg RTD. Auctioneered low reactor coolant pressure
Qualifications (seismic, environmental)	Seismic and environmental
Calculational Technical (steam tables, functional fit, ranges)	Functional fit - ambient to critical point
Input	
Temperature (RTDs or T/Cs)	RTDs, T/Cs, and Tref
Temperature (number of sensors and locations)	RTDs - 2 hot leg and 2 cold leg/channel T/Cs - 25 per channel
Range of temperature sensors	RTDs - 0-700°F T/Cs - 0-2300°F Calibration unit range - 0-2300°F
Uncertainty* of temperature sensors	See WCAP 8587
Qualifications (seismic, environmental)	Seismic and environmental as classified in Section 18.2.13.2

TABLE 18.2-3 (Sheet 3)

Pressure (specify instrument used)	Qualified Pressure Transmitter
Pressure (number of sensors and locations)	1 wide range - RCS loop 2 narrow range - pressurizer
Range of pressure sensors	Wide range 0-3000 psi narrow range 1700-2500 psi
Uncertainty* of pressure sensors	See WCAP 8587
Qualifications (seismic, environmental)	Seismic and environmental

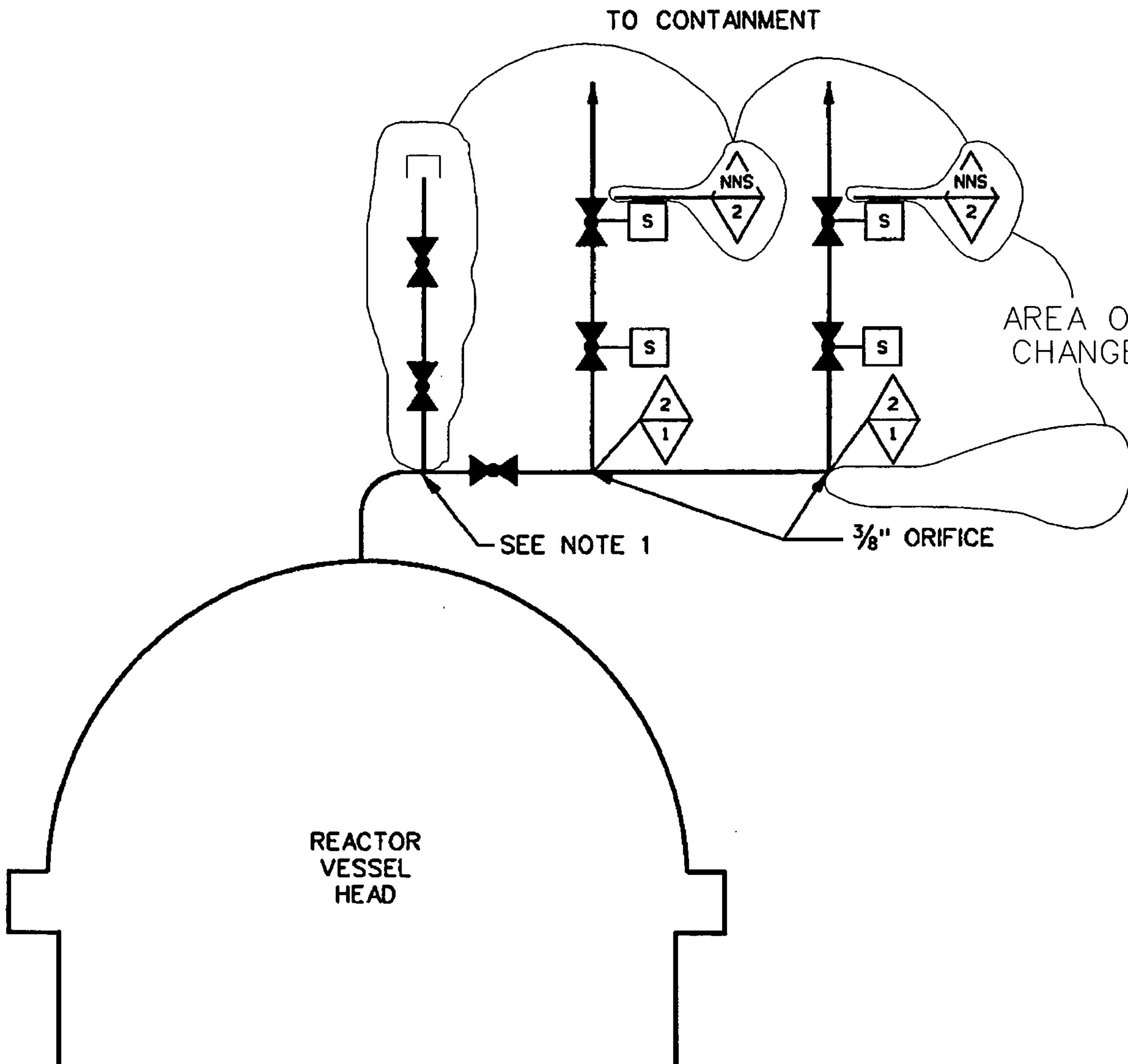
*Uncertainties must address conditions of forced flow and natural circulation.

TABLE 18.2-4
NARROW RANGE MEASUREMENT UNCERTAINTY FOR
REACTOR VESSEL LEVEL INSTRUMENTATION SYSTEM

	Component and Uncertainty Definition	Uncertainty Level, percent
a.	Differential pressure transmitter calibration and drift allowance (+1.5 percent of span) multiplied by the ratio of ambient to operating water density.	±2.1
b.	Differential pressure transmitter allowance for change in calibration due to ambient temperature change (±0.5 percent of span for +50°F) multiplied by the density ratio.	±0.7
c.	Differential pressure transmitter allowance for change in calibration due to change in system pressure (±0.2 percent of span per 1000 psi change) multiplied by the density ratio.	±0.34
d.	Differential pressure transmitter allowance for change in calibration due to exposure to long-term overrange (±0.5 percent of span) multiplied by the density ratio.	±0.7
e.	Reference leg temperature instrument (RTD) uncertainty of ±5°F and/or allowance of ±5°F for the difference between the measurement and the true average temperature of the reference leg, applied to each vertical section of the reference leg where a measurement is made. Stated uncertainty is based on a maximum containment temperature of 420°F, and a typical reference leg installation.	±0.64

TABLE 18.2-4 (Sheet 2)

	Component and Uncertainty Definition	Uncertainty Level, percent
f.	Reactor coolant density based on auctioneering for highest water density obtained from hot leg temperature (±6 F) or system pressure (+6 psi). Magnitude of uncertainty varies with system pressure and water level, with largest uncertainty occurring when the reactor vessel is full.	±2.3
g.	Sensor and hydraulic isolator bellows displacements due to system pressure changes or reference leg temperature changes will introduce minor errors in the level measurement due to the small volumes and small bellows spring constants. The changes, such as pressure or temperature, tend to cancel; i.e., the bellows associated with each measurement move in the same direction. Maximum expected error due to differences in capillary line volume and local temperatures is equivalent to a level change of about 5 inches, multiplied by the density ratio.	±1.46
h.	Density function generator output mismatch with ASME Steam Tables limited to this maximum.	±0.50
i.	Overall uncertainty of electronics system calibration is limited to less than this amount.	±1.0
j.	Control board indicator resolution.	±0.5



NOTES:
1. EXISTING VENT LINE

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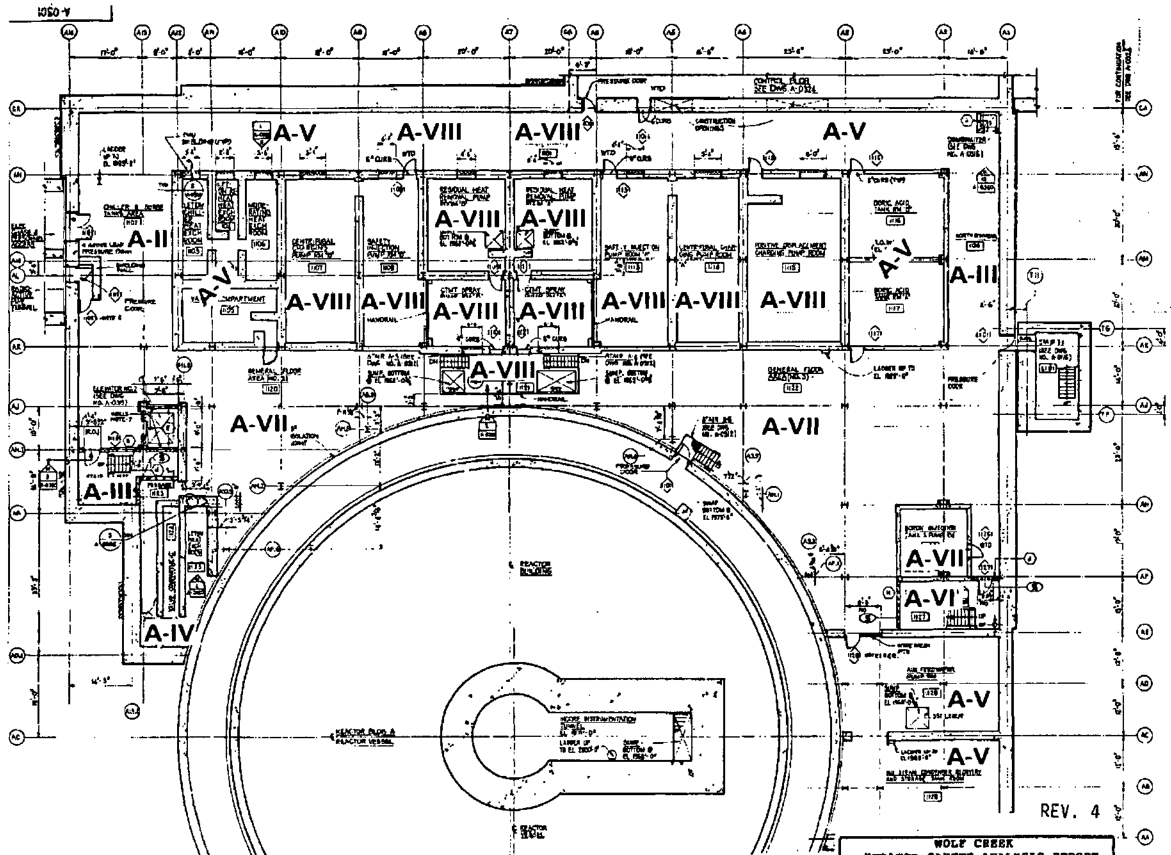
FIGURE 18.2-1

REACTOR HEAD VENT SYSTEM



REV. 4

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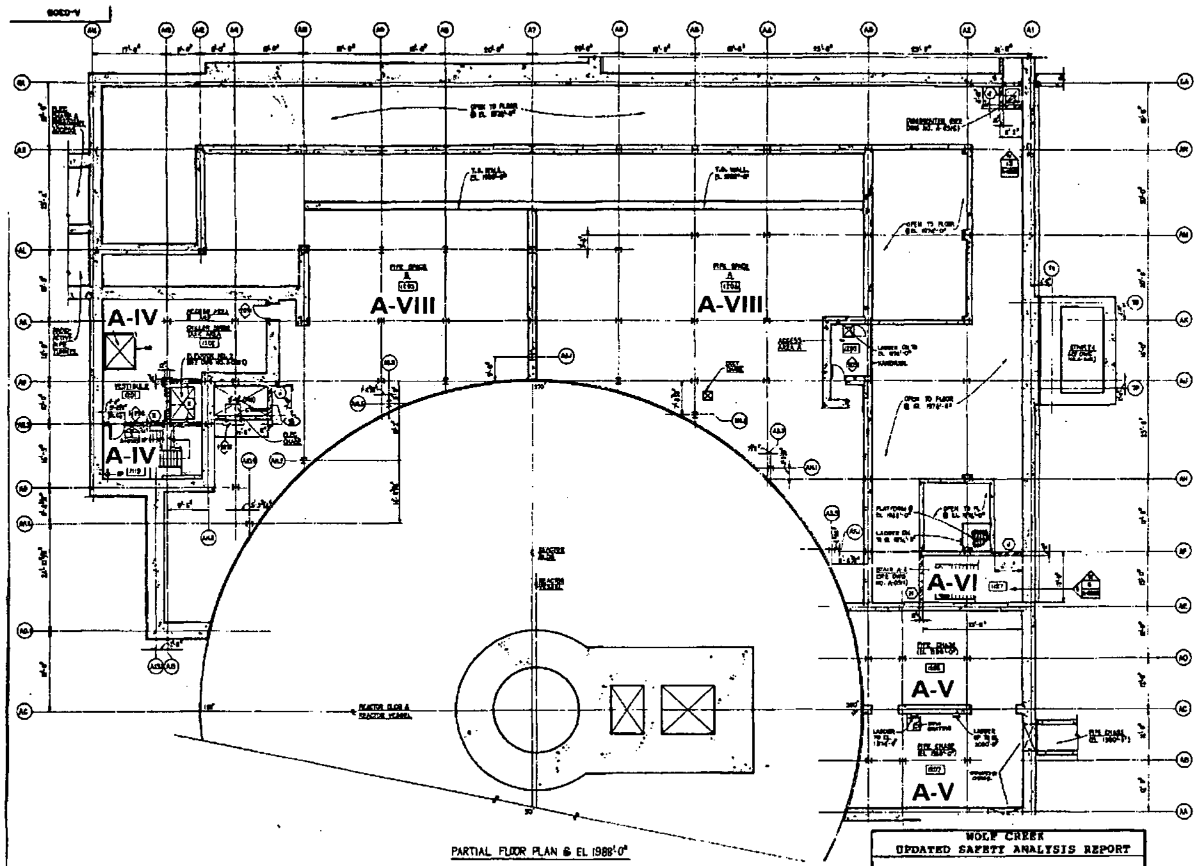
FIGURE 18.2-2

POST-ACCIDENT RADIATION ZONES
ELEVATION 1974'

WOLF CREEK



Rev. 0

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FIGURE 18.2-3

POST-ACCIDENT RADIATION ZONES ELEVATION 1988'

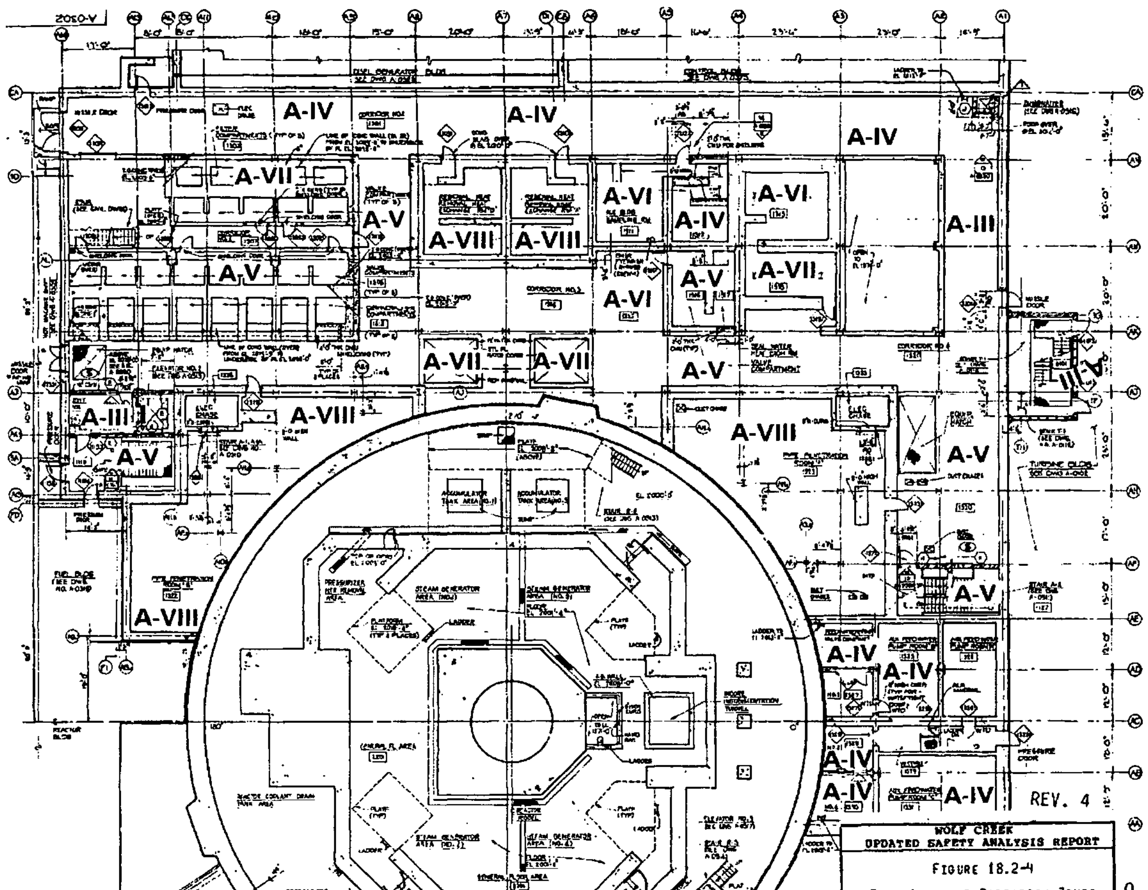

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FIGURE 18.2-4

POST-ACCIDENT RADIATION ZONES
ELEVATION 2000'

0

WOLF CREEK

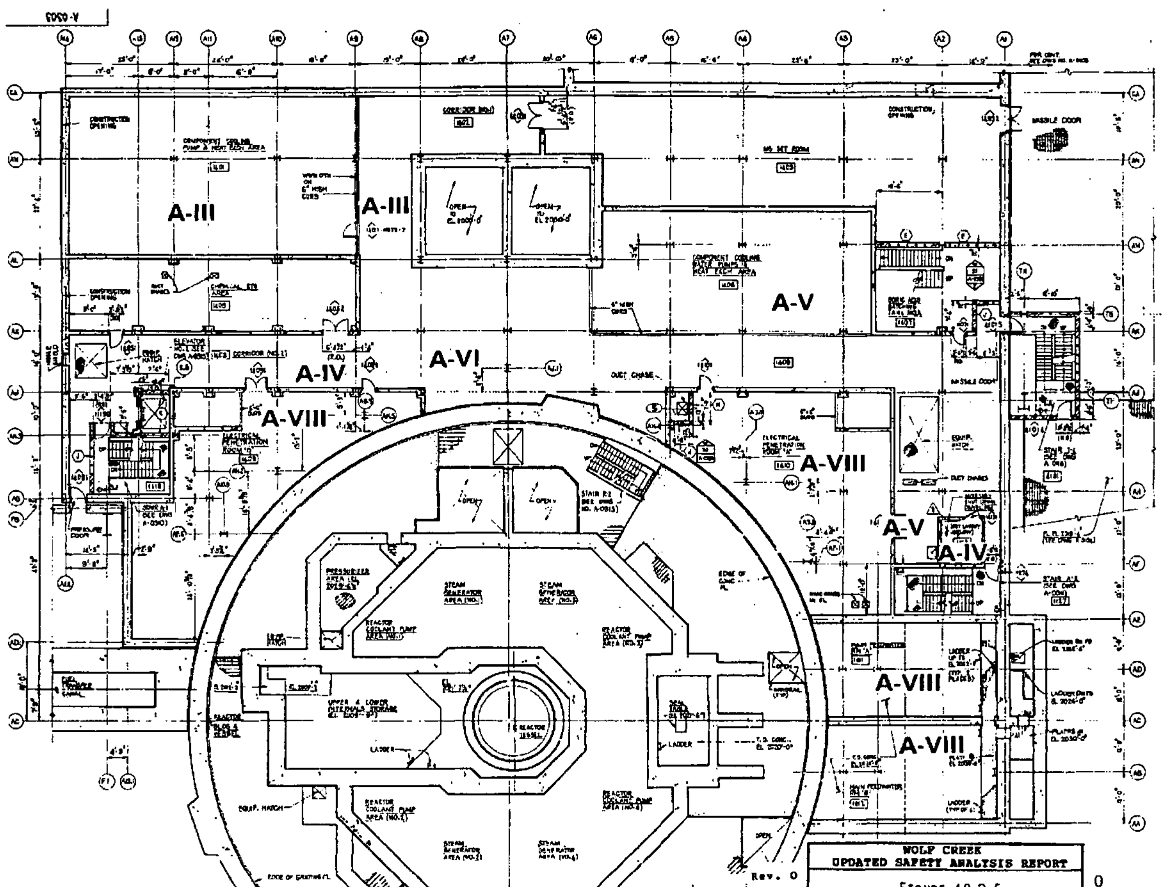

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FIGURE 18.2-5

POST-ACCIDENT RADIATION ZONES
ELEVATION 2026'

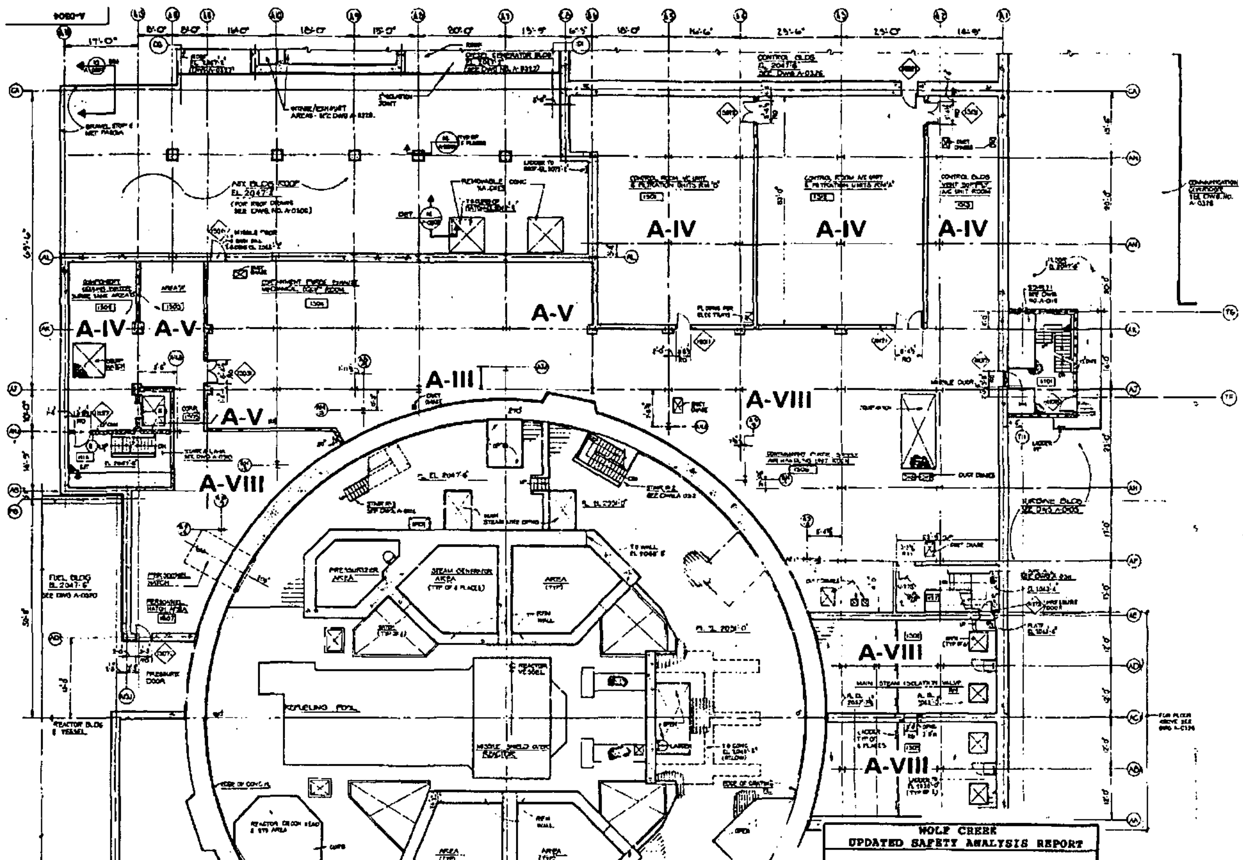

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FIGURE 18.2-6

POST-ACCIDENT RADIATION ZONES
ELEVATION 2047'-6"

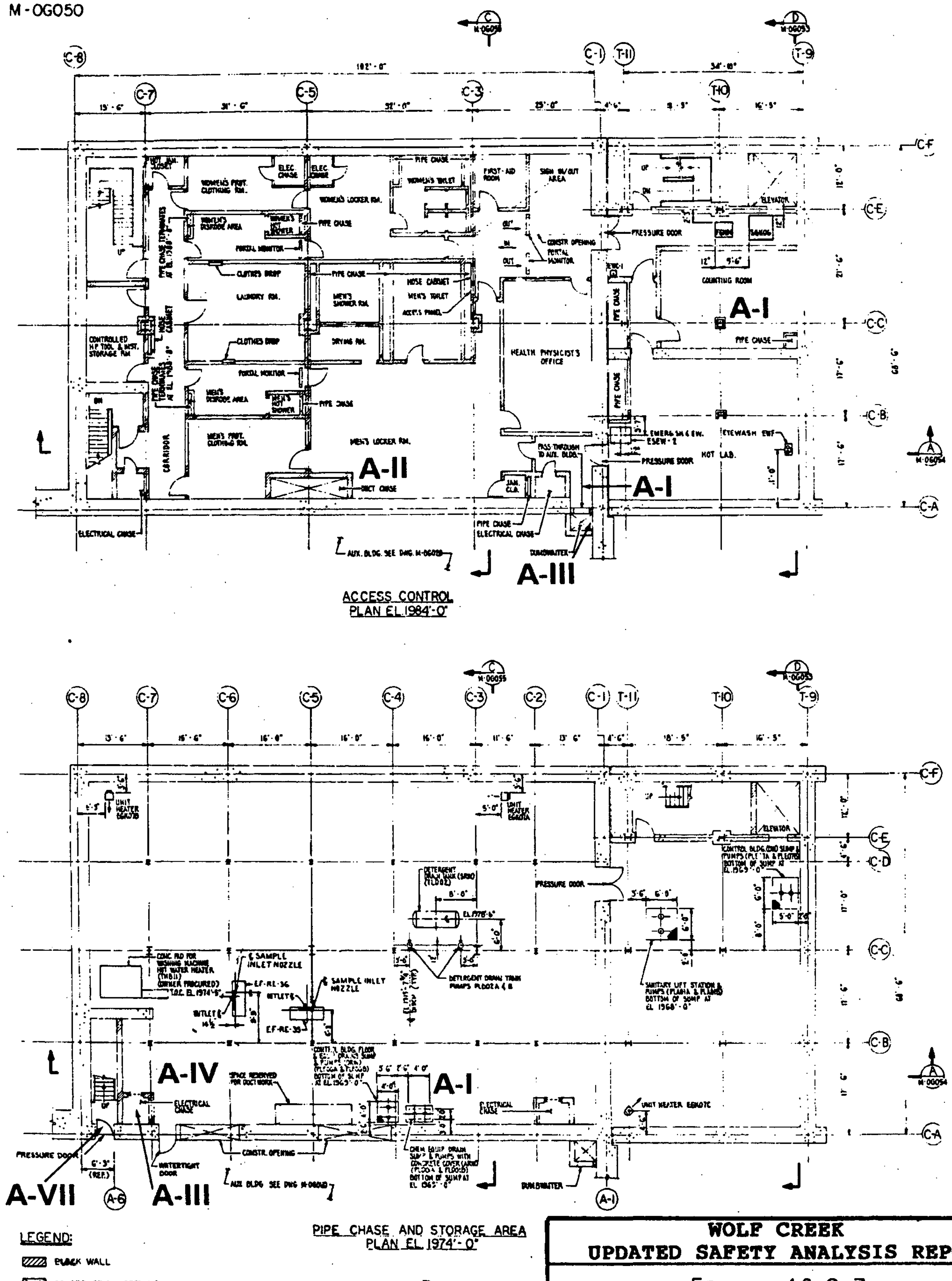

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FIGURE 18.2-7

POST-ACCIDENT RADIATION ZONES CONTROL BLDG. AND COMMUNICATION CORRIDOR ELEVATIONS 1974' AND 1984'

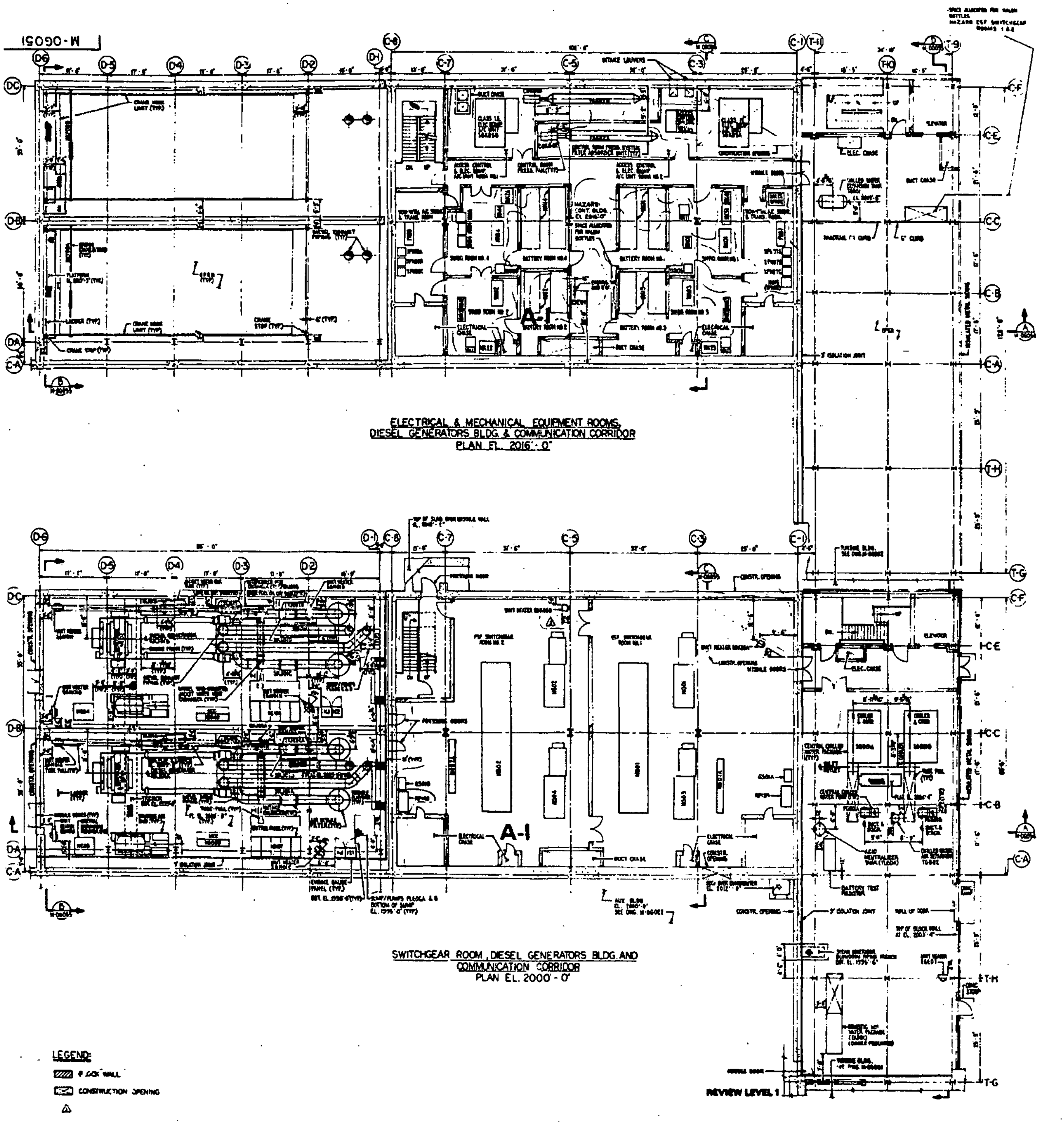

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FIGURE 18.2-8

POST-ACCIDENT RADIATION ZONES CONTROL AND DIESEL GENERATOR BUILDINGS AND COMMUNICATION CORRIDOR ELEVATIONS 2000' AND 2016'

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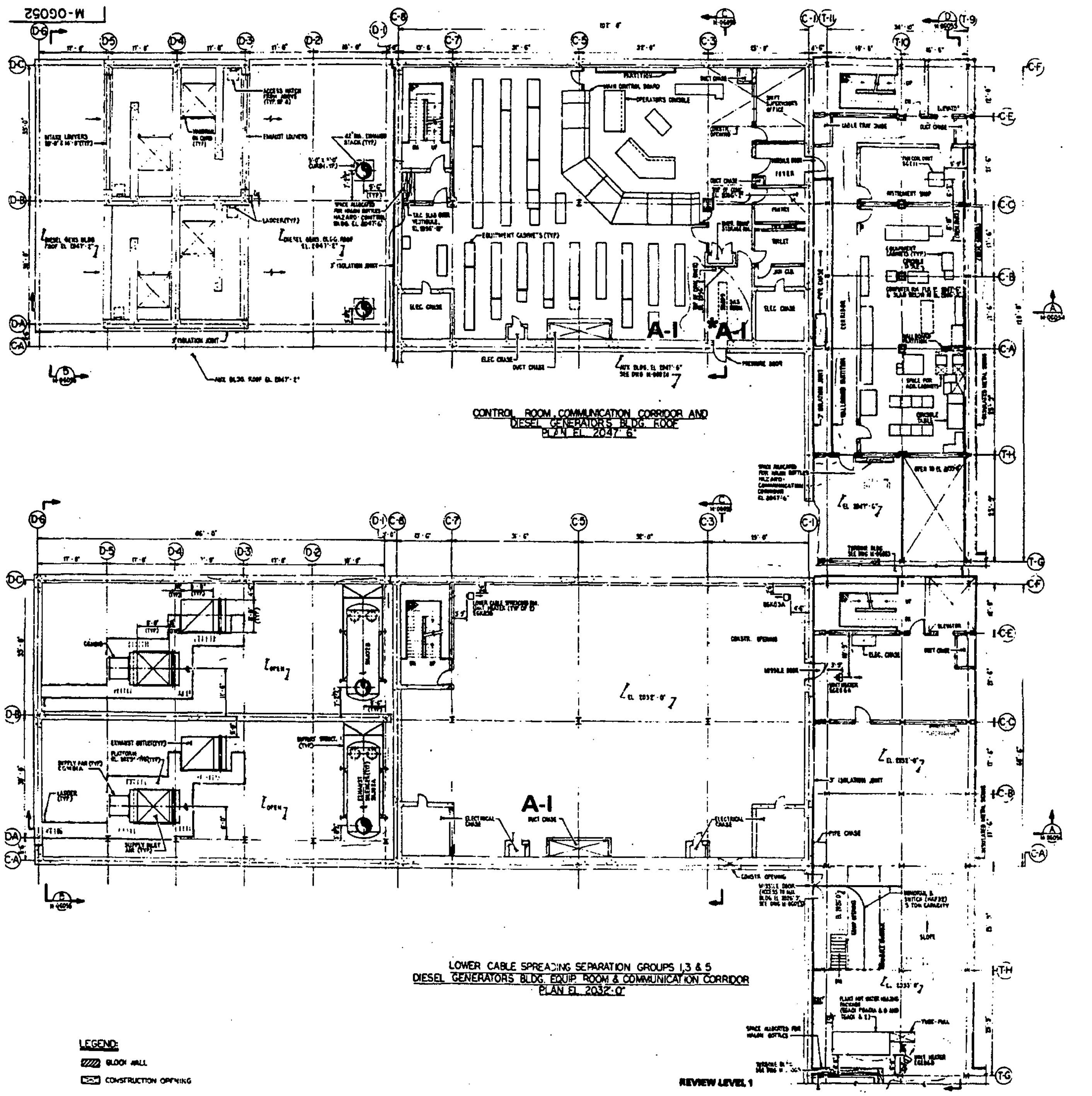

* 30 - Day Average

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FIGURE 18.2-9

POST ACCIDENT RADIATION ZONES CONTROL & DIESEL GENERATOR BUILDINGS AND COMMUNICATION CORRIDOR ELEVATIONS 2032' & 2047'-6"

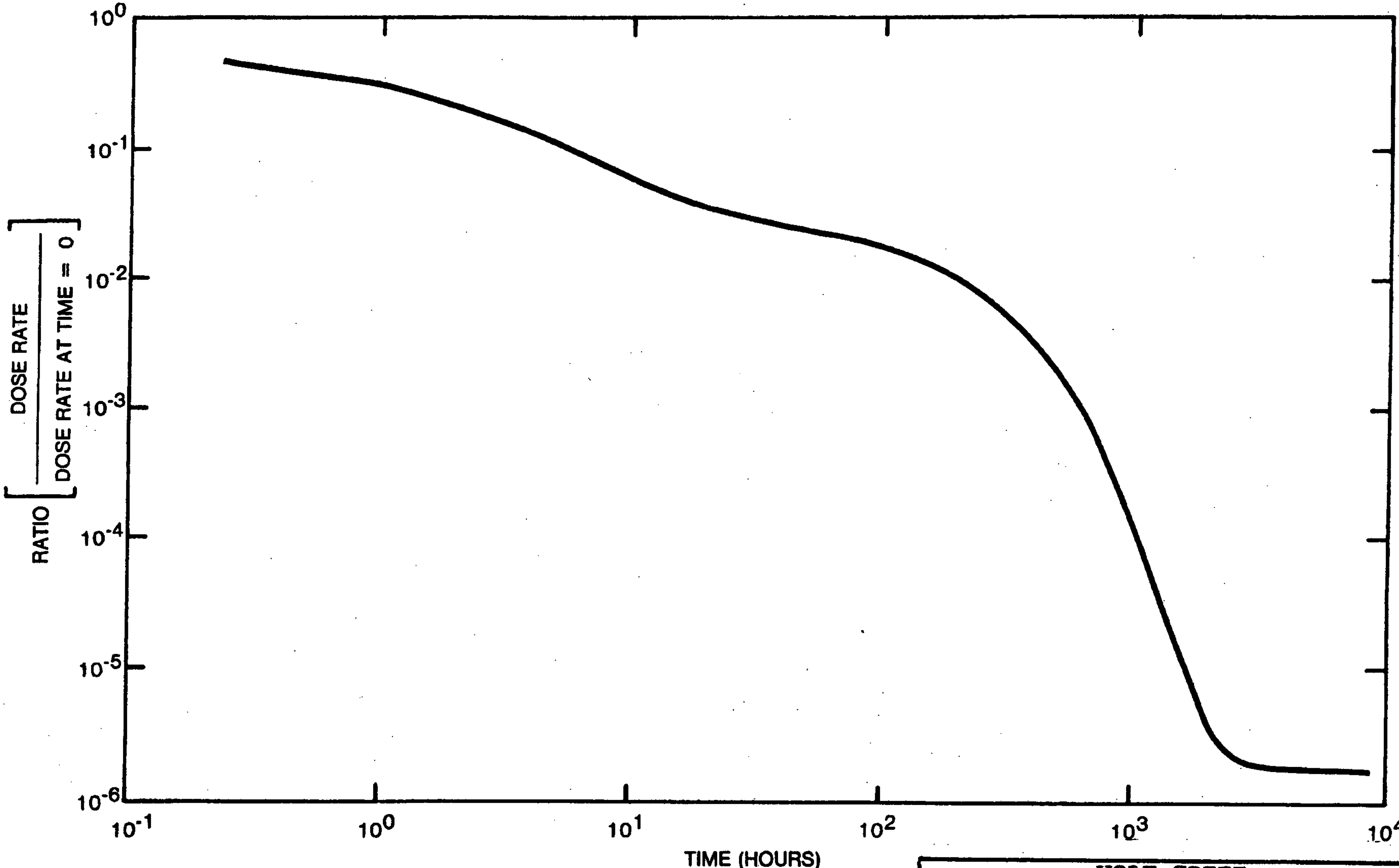

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FIGURE 18.2-10

NORMALIZED DOSE RATE DECAY CURVE FOR AIRBORNE SOURCE (SOURCE A)

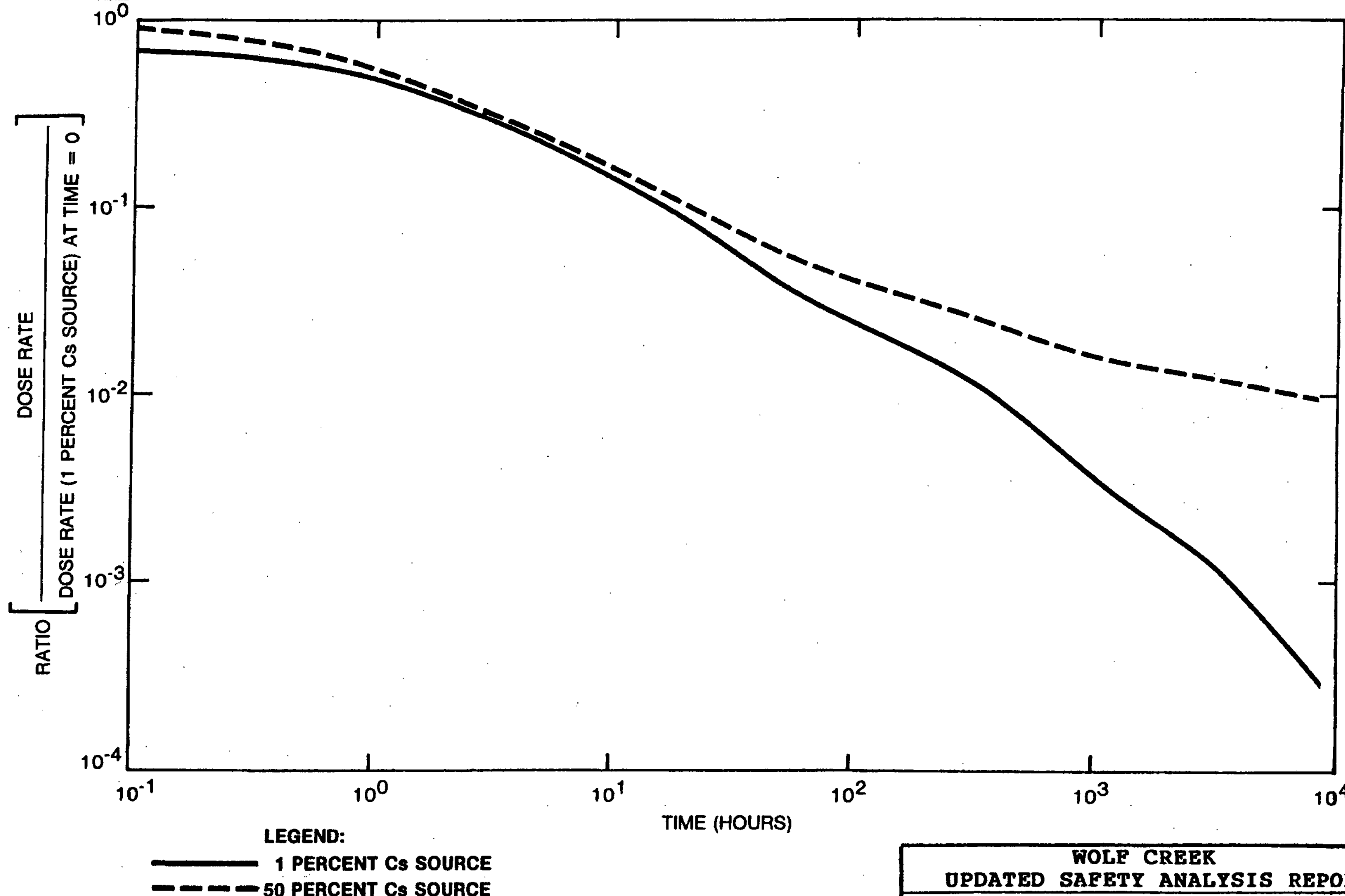

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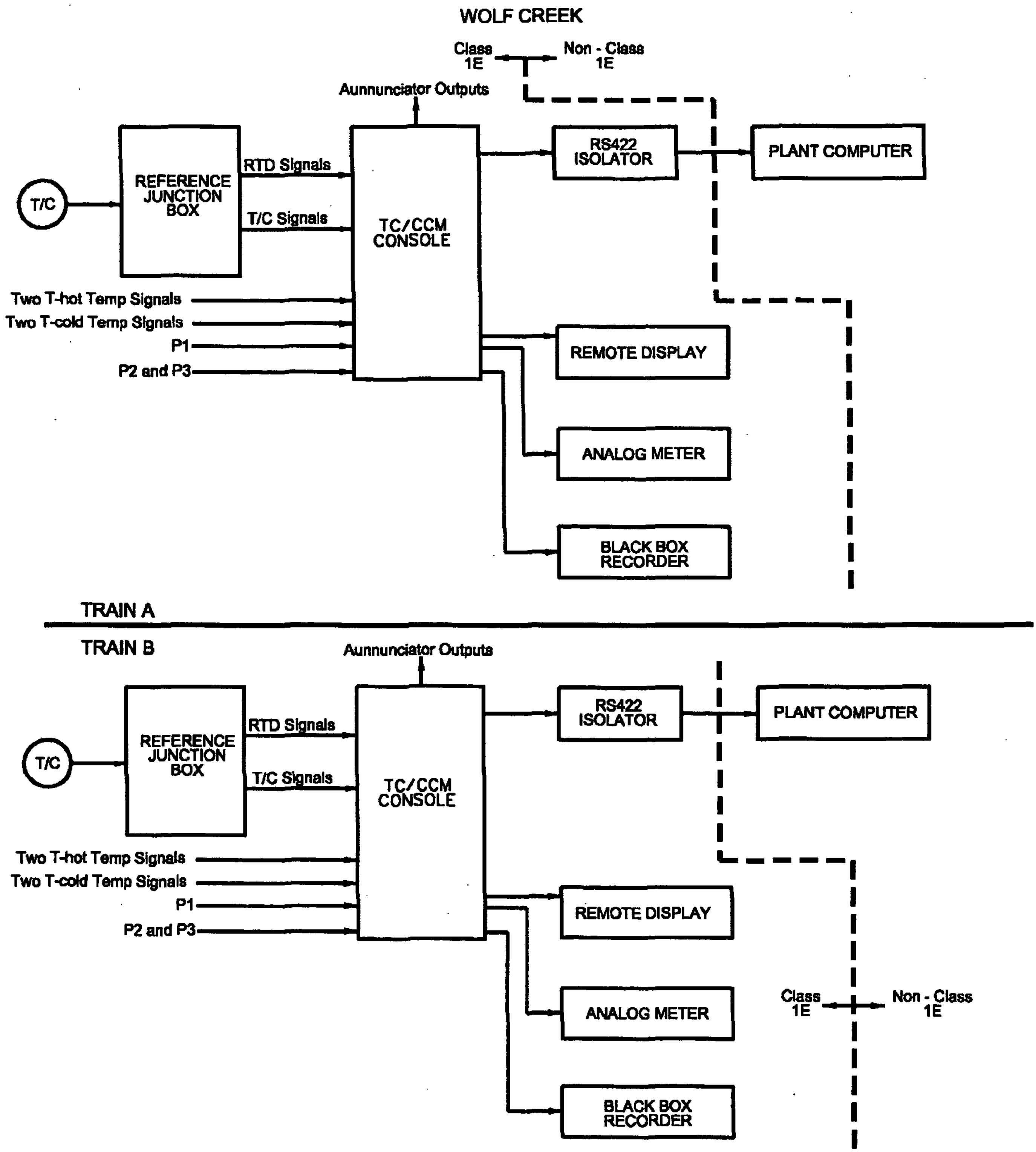
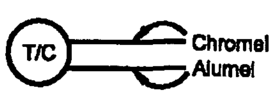
FIGURE 18.2-11

NORMALIZED DOSE RATE DECAY CURVES FOR SUMP SOURCE (SOURCE C) WITH 1 PERCENT C_S AND 50 PERCENT C_S



Notes:
1. P1 is a wide range loop pressure.
2. P2 and P3 are narrow range pressurizer pressures.
3. Material type for T/C is shown below. Type K extension wire size is 22 AWG chromel/alumel wire.

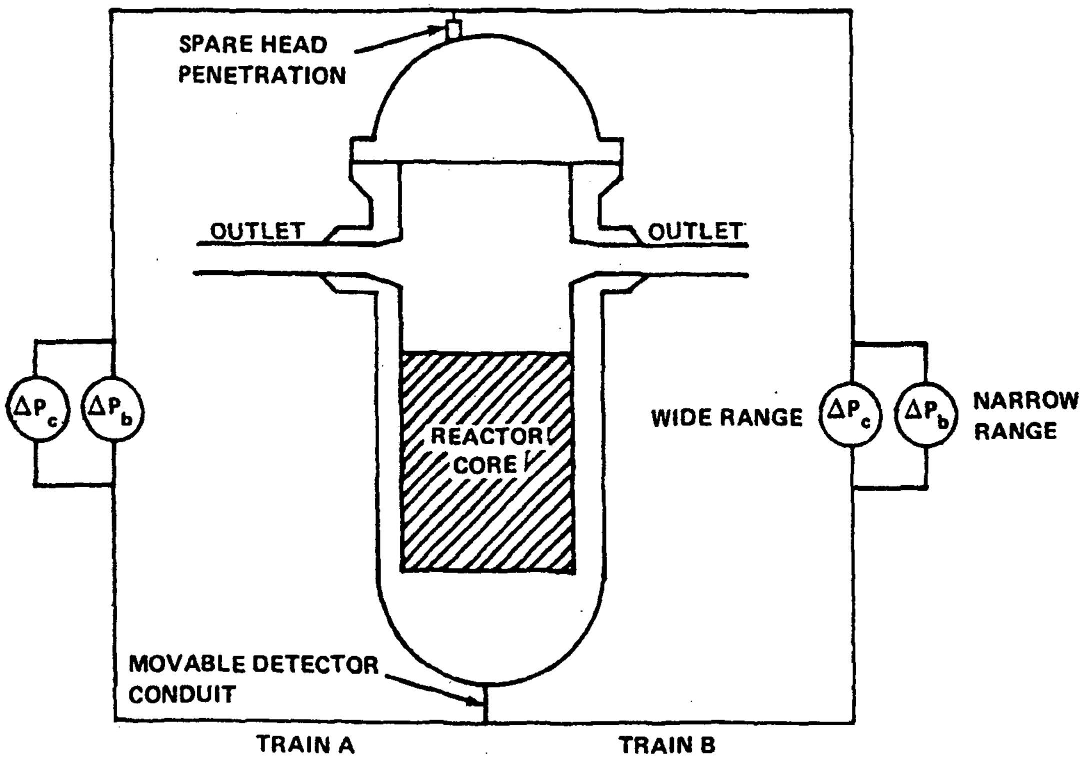


REV. 28

WOLF CREEK
UPDATE SAFETY ANALYSIS REPORT

Figure 18.2-12

Functional Diagram (Reactor Core Subcooling Monitor)

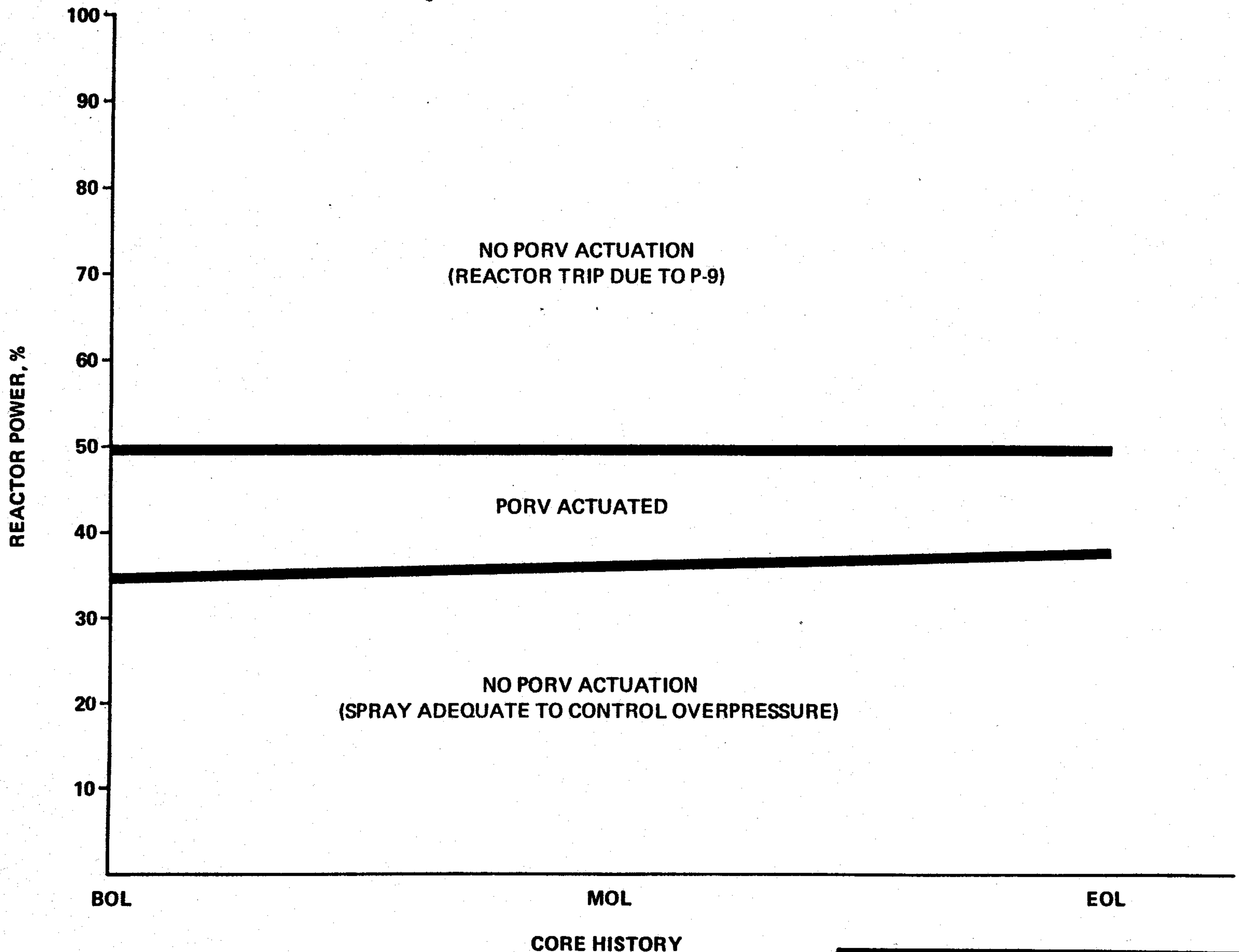


Rev. 0

WOLF CREEK
UPDATED SAFETY ANALYSIS REPORT

FIGURE 18.2-13

REACTOR VESSEL LEVEL
INSTRUMENTATION SYSTEM



Rev. 0

WOLF CREEK
UPDATED SAFETY ANALYSIS REPORT

FIGURE 18.2-14

PORV OPENING BAND - TURBINE TRIP WITH CONDENSER UNAVAILABLE

18.3 EMERGENCY PREPARATIONS AND RADIATION PROTECTION

18.3.1 UPGRADE EMERGENCY PREPAREDNESS (III.A.1.1)

18.3.1.1 NRC Guidance per NUREG-0694

Position

Provide an emergency response plan in substantial compliance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," except that only a description of and completion schedule for the means for providing prompt notification to the population (App. 3), the staffing for emergencies in addition to that already required (Table B.1), and an upgraded meteorological program (App. 2) need be provided. NRC will give substantial weight to Federal Emergency Management Agency (FEMA) findings on offsite plans in judging the adequacy against NUREG-0654. Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations. This requirement shall be met before issuance of a full-power license.

18.3.1.2 The Operating Agent Response

The Operating Agent has prepared and filed with the NRC on April 7, 1981 the "Radiological Emergency Response Plan for the Wolf Creek Generating Station." This plan and subsequent revisions were prepared to meet the requirements of 10 CFR Part 50, Section 50.47 and Appendix E. The plan has been prepared with consideration given to additional NRC emergency planning guidance presented in NUREG-0654. Compliance with NRC requirements has been addressed in Supplement 6 to the WCGS Safety Evaluation Report, NUREG-0881.

18.3.1.3 Conclusion

The Operating Agent has provided the NRC documentation relative to the emergency planning activities at WCGS which satisfies the requirements of 10 CFR Part 50, Section 50.47 and Appendix E, and the supplementary NRC guidance in NUREG-0694.

18.3.2 UPGRADE EMERGENCY SUPPORT FACILITIES (III.A.1.2)

18.3.2.1 NRC Guidance Per NUREG-0578 and NUREG-0694

(A) ONSITE TECHNICAL SUPPORT CENTER (NUREG-0578, ITEM 2.2.2.b)

(See Section 18.4 for Updated Information)

Position

Each operating nuclear power plant shall maintain an onsite Technical Support Center (TSC) separate from and in close proximity to the control room that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the technical support center. Records that pertain to the as-built conditions and layout of structures, systems, and components shall be readily available to personnel in the TSC.

Clarification (NRC Letter dated November 9, 1979)

1. By January 1, 1980, each licensee should meet items a-g that follow. Each licensee is encouraged to provide additional upgrading of the TSC (items b-g) as soon as practical, but no later than January 1, 1981.

   a. Establish a TSC and provide a complete description.

   b. Provide plans and procedures for engineering/ management support and staffing of the TSC.

   c. Install dedicated communications between the TSC and the control room, near-site emergency operations center, and the NRC.

   d. Provide monitoring (either portable or permanent) for both direct radiation and airborne radioactive contaminants. The monitors should provide warning if the radiation levels in the support center are reaching potentially dangerous levels. The licensee should designate action levels to define when protective measures should be taken (such as using breathing apparatus and potassium iodide tablets or evacuation to the control room).

   e. Assimilate or ensure access to technical data, including the licensee's best effort to have direct display of plant parameters necessary for assessment in the TSC.

   f. Develop procedures for performing this accident assessment function from the control room should the TSC become uninhabitable.

g. Submit to the NRC a longer range plan for upgrading the TSC to meet all requirements.

2. Location

It is recommended that the TSC be located in close proximity to the control room to ease communications and access to technical information during an emergency. The center should be located onsite, i.e., within the plant security boundary. The greater the distance from the control room, the more sophisticated and complete should be the communications and availability of technical information. Consideration should be given to providing key TSC personnel with a means for gaining access to the control room.

3. Physical Size and Staffing

The TSC should be large enough to house 25 persons, necessary engineering data, and information displays (TV monitors, recorders, etc.). Each licensee should specify staffing levels and disciplines reporting to the TSC for emergencies of varying severity.

4. Activation

The center should be activated in accordance with the "Alert" level as defined in the NRC document "Draft Emergency Action Level Guidelines, NUREG-0610" dated September 1979, and currently out for public comment. Instrumentation in the TSC should be capable of providing displays of vital plant parameters from the time the accident began (t = 0 defined as either reactor or turbine trip). The STA should be consulted on the "Notification of Unusual Event." However, the activation of the TSC is discretionary for that class of event.

5. Instrumentation

The instrumentation to be located in the TSC need not meet safety-grade requirements but should be qualitatively comparable (as regards accuracy and reliability) to that in the control room. The TSC should have the capability to access and display plant parameters independent from actions in the control room. Careful consideration should be given to the design of the interface of the TSC instrumentation to ensure that addition of the TSC will not result in any degradation of the control room or other plant functions.

6. Instrumentation Power Supply

The power supply to the TSC instrumentation need not meet safety-grade requirements, but should be reliable and of a quality compatible with the TSC instrumentation requirements. To ensure continuity of information at the TSC, the power supply provided should be continuous once the TSC is activated. Consideration should be given to avoid loss of stored data (e.g., plant computer) due to momentary loss of power or switching transients. If the power supply is provided from a plant safety-related power source, careful attention should be given to ensure that the capability and reliability of the safety-related power source is not degraded as a result of this modification.

7. Technical Data

Each licensee should establish the technical data requirements for the TSC, keeping in mind the accident assessment function that has been established for those persons reporting to the TSC during an emergency. As a minimum, data (historical in addition to current status) should be available to permit the assessment of:

a. Plant Safety System Parameters for:

(1) Reactor Coolant System

(2) Secondary System (PWRs)

(3) Emergency Core Cooling Systems

(4) Feedwater and Makeup Systems

(5) Containment

b. Inplant Radiological Parameters for:

(1) Reactor Coolant System

(2) Containment

(3) Effluent Treatment

(4) Release Paths

c. Offsite Radiological for:

(1) Meteorology

(2) Offsite Radiation Levels

8. <u>Data Transmission</u>

In addition to providing a data transmission link between the TSC and the control room, each licensee should review current technology as regards transmission of those parameters identified for TSC display. Although there is not a requirement at the present time, each licensee should investigate the capability to transmit plant data offsite to the Emergency Operations Center (EOC), the NRC, the reactor vendor, etc.

9. <u>Structural Integrity</u>

a. The TSC need not be designed to seismic Category I requirements. The center should be well built in accordance with sound engineering practice with due consideration to the effects of natural phenomena that may occur at the site.

b. Since the center need not be designed to the same stringent requirements as the control room, each licensee should prepare a backup plan for responding to an emergency from the control room.

10. <u>Habitability</u>

The licensee should provide protection for the TSC personnel from radiological hazards, including direct radiation and airborne contaminants, as per General Design Criterion (GDC) 19 and SRP 6.4.

a. Licensee should ensure that personnel inside the TSC will not receive doses in excess of those specified in GDC-19 and SRP 6.4 (i.e., 5 rem whole-body and 30 rem to the thyroid for the duration of the accident). Major sources of radiation should be considered.

b. Permanent monitoring systems should be provided to continuously indicate radiation dose rates and airborne radioactivity concentrations inside the TSC. The monitoring systems should include local alarms to warn personnel of adverse conditions.

Procedures must be provided which will specify appropriate protective actions to be taken in the event that high dose rates or airborne radioactive concentrations exist.

c. Permanent ventilation systems which include particulate and charcoal filters should be provided. The ventilation systems need not be qualified as ESF systems. The design and testing guidance of Regulatory Guide 1.52 should be followed, except that the systems do not have to be redundant, seismic, instrumented in the control room, or automatically activated. In addition, the HEPA filters need not be tested as specified in Regulatory Guide 1.52, and the HEPAs do not have to meet the QA requirements of Appendix B to 10 CFR 50. However, spare parts should be readily available and procedures in place for replacing failed components during an accident. The systems should be designed to operate from the emergency power supply.

d. Dose reduction measures such as breathing apparatus and potassium iodide tablets cannot be used as a design basis for the TSC in lieu of ventilation systems with charcoal filters. However, potassium iodide and breathing apparatus should be available.

(B) ONSITE OPERATIONAL SUPPORT CENTER (NUREG-0578, Item 2.2.2.c)

Position

An area to be designated as the onsite Operational Support Center (OSC) shall be established. It shall be separate from the control room and shall be the place to which the operations support personnel will report in an emergency situation. Communications with the control room shall be provided. The emergency plan shall be revised to reflect the existence of the center and to establish the methods and lines of communication and management.

(C) NEAR-SITE EMERGENCY OPERATION FACILITY (NUREG-0694)
(See Section 18.4 for Updated Information)

Position

Designate a near-site emergency operations facility with communications with the plant to provide evaluation of radiation releases and coordination of all onsite and offsite activities during an accident.

Provide shielding against direct radiation, ventilation isolation capability, dedicated communications with the onsite Technical Support Center, and direct display of radiological and meteorological parameters.

18.3.2.2 The Operating Agent Response

The Operating Agent prepared a detailed description of each emergency response facility: the onsite TSC, the onsite OSC, and the near-site EOF. This report submitted by SNUPPS letter dated June 4, 1981, contains a complete functional system description for each facility which describes the data acquisition display and transmittal systems selected for each facility. The report, in addition, discusses the size, location, and habitability specifications to which the facilities have been designed. The design of the emergency facilities for WCGS has been prepared in consideration of the 10 CFR Part 50, Appendix E legal requirement and the guidance presented in NUREG-0696 and NUREG-0654.

NRC Generic Letter 82-33, dated December 17, 1982, provided guidance for meeting regulatory requirements for, among other issues, NUREG-0737, Item III.A.1.2. Based on the NRC review of the response to Generic Letter 82-33 (SNUPPS letter dated April 15, 1983), a license condition was issued which required that the TSC and EOF be operational prior to startup following the first refueling outage at WCGS. As discussed in Supplement 4 to the WCGS Safety Evaluation Report, the NRC will conduct a post-implementation appraisal of WCGS Emergency Response Facilities.

18.3.2.3 Conclusion

The functional description of each emergency response facility at WCGS filed with the NRC on June 1, 1981 detailed the means by which the Operating Agent meets the appropriate NRC guidance.

18.3.3 IMPROVING LICENSEE EMERGENCY PREPAREDNESS - LONG-TERM (III.A.2)

18.3.3.1 NRC Guidance Per NUREG-0737

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

Clarification

In accordance with Task Action Plan Item III.A.1.1, "Upgrade Emergency Preparedness," each nuclear power facility was required to immediately upgrade its emergency plans with criteria provided October 10, 1979, as revised by NUREG-0654 (FEMA-REP-1, issued for interim use and comment, January 1980). New plans were submitted by January 1, 1980, using the October 10, 1979 criteria. Reviews were started on the upgraded plans using NUREG-0654. Concomitant to these actions, amendments were developed to 10 CFR Part 50 and Appendix E to 10 CFR Part 50, to provide the long-term implementation requirements. These new rules were issued in the Federal Register on August 19, 1980, with an effective date of November 3, 1980. The revised rules delineate requirements for emergency preparedness at nuclear reactor facilities.

NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," provides detailed items to be included in the upgraded emergency plans and, along with the revised rules, provides for meteorological criteria, means for providing for a prompt notification to the population, and the need for emergency response facilities (see Item III.A.1.2 [of NUREG-0737]).

Implementation of the new rules levied the requirement for the licensee to provide procedures implementing the upgraded emergency plans to the NRC for review. Publication of Revision 1 to NUREG-0654 (FEMA-REP-1) which incorporates the many public comments received is expected in October 1980. This is the document that will be used by the NRC and FEMA in their evaluation of emergency plans submitted in accordance with the new NRC rules.

NUREG-0654, Revision 1; NUREG-0696, "Functional Criteria for Emergency Response Facilities;" and the amendments to 10 CFR Part 50 and Appendix E to 10 CFR Part 50 regarding emergency preparedness, provide more detailed criteria for emergency plans, design, and functional criteria for emergency response facilities and establishes firm dates for submission of upgraded emergency plans for installation of prompt notification systems. These revised criteria and rules supersede previous Commission guidance for the upgrading of emergency preparedness at nuclear power facilities.

Revision 1 to NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," provides meteorological criteria to fulfill, in part, the standard that "Adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use" (see 10 CFR 50.47). The position in Appendix 2 to NUREG-0654 outlines four essential elements that can be categorized into three functions: measurements, assessment, and communications.

Proposed Revision 1 to Regulatory Guide 1.23, "Meteorological Measurements Programs in Support of Nuclear Power Plants," has been adopted to provide guidance criteria for the primary meteorological measurements program consisting of a primary system and secondary system(s) where necessary, and a backup system. Data collected from these systems are intended for use in the assessment of the offsite consequences of a radiological emergency condition.

Appendix 2 to NUREG-0654 delineates two classes of assessment capabilities to provide input for the evaluation of offsite consequences of a radiological emergency condition. Both classes of capabilities provide input to decisions regarding emergency actions. The Class A capability should provide information to determine the necessity for notification, sheltering, evacuation, and, during the initial phase of a radiological emergency, making confirmatory radiological measurements. The Class B capability should provide information regarding the placement of supplemental meteorological monitoring equipment, and the need to make additional confirmatory radiological measurements. The Class B capability shall identify the areas of contaminated property and foodstuff requiring protective measures and may also provide information to determine the necessity for sheltering and evacuation.

Proposed Revision 1 to Regulatory Guide 1.23 outlines the set of meteorological measurements that should be accessible from a system that can be interrogated; the meteorological data should be presented in the prescribed format. The results of the assessments should be accessible from this system; this information should incorporate human-factors engineering in its display to convey the essential information to the initial decision makers and subsequent management team. An integrated system should allow the eventual incorporation of effluent monitoring and radiological monitoring information with the environmental transport to provide direct dose consequence assessments.

Requirements of the new emergency-preparedness rules under Paragraphs 50.47 and 50.54 and the revised Appendix E to Part 50 taken together with NUREG-0654 Revision 1 and NUREG-0696, when approved for issuance, go beyond the previous requirements for meteorological programs. To provide a realistic time frame for implementation, a staged schedule has been established with compensating actions provided for interim measures.

18.3.3.2 The Operating Agent Response

See Section 18.3.1.2.

18.3.3.3 Conclusion

See Section 18.3.1.3.

18.3.4 INTEGRITY OF SYSTEMS OUTSIDE OF CONTAINMENT (III.D.1.1)

18.3.4.1 NRC Guidance Per NUREG-0737

Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

1. Immediate leak reduction

   a. Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

   b. Measure actual leakage rates with system in operation and report them to the NRC.

2. Continuing Leak Reduction -- Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

Clarification

Applicants shall provide a summary description, together with initial leak-test results, of their program to reduce leakage from systems outside the containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident.

1. Systems that should be leak tested are as follows (any other plant system which has similar functions or postaccident characteristics, even though not specified herein, should be included):

Residual heat removal (RHR)

Containment spray recirculation

High-pressure injection recirculation

Containment and primary coolant sampling

Reactor core isolation cooling

Makeup and letdown (PWRs only)

Waste gas (includes headers and cover gas system outside of the containment in addition to decay or storage system)

Include a list of systems containing radioactive materials which are excluded from program and provide justification for exclusion.

2. Testing of gaseous systems should include helium leak detection or equivalent testing methods.

3. Should consider program to reduce leakage potential release paths due to design and operator deficiencies as discussed in our letter to all operating nuclear power plants regarding North Anna and related incidents dated October 17, 1979.

18.3.4.2 The Operating Agent Response

This defines the operating agent’s program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems considered include the recirculation portion of the containment spray system, safety injection system, chemical and volume control system,and residual heat removal system. The program is as follows:

1. General Practical Leak Reduction Measures

Operations, via their normal duties and responsibilities, perform routine rounds in the auxiliary and radwaste buildings. These help assure the integrity of systems which routinely contain radioactive fluids or gases. Identification of leakage and initiation of appropriate corrective is one of the objectives of routine operator rounds, consistent with keeping occupational and routine releases as low as reasonable achievable.

Maintenance, as directed by the corrective action program, performs repair/rework on all components as needed to correct leaks.

2. Periodic Visual Inspection

In accordance with administrative procedures, Operations performs a periodic visual inspection, on a refueling cycle basis, of the recirculation portion of the containment spray system, safety injection system, chemical and volume control system and residual heat removal system. These procedures require measurement of leakage rates and initiation of corrective action for any and all detectable leaks.

3. Additional Programs Resulting in Detection and Reduction of Leakage

WCNOC has a Managed Maintenance Program, which includes preventive maintenance activities based on experience, engineering judgment, inspection, testing and replacement of items which have a specific lifetime such as wear rings, bearings, seals, and packing.

WCNOC is also committed to ASME Section XI Inservice Inspection Program using the ASME Code.

A description of the WCGS program is documented in KMLNRC 84-46, dated March 30, 1984. Amendment No. 137 eliminated the requirements for PASS. The PASS system has been abandoned in place.

18.3.4.3 Conclusion

The WCGS design includes provisions to insure the integrity of fluids systems which are postulated to contain highly contaminated fluids following a design basis accident. The provision is based on the preservice and inservice tests required by the ASME Code and programmatic controls implemented by the Operating Agent. These provisions provide assurance that these systems perform their intended functions, including leaktightness, following a design basis accident. This commitment satisfies Item III.D.1.1 of NUREG-0737 and Amendment No. 137.

18.3.5 IMPROVED INPLANT IODINE INSTRUMENTATION UNDER ACCIDENT CONDITIONS (III.D.3.3)

18.3.5.1 NRC Guidance Per NUREG-0737

Position

a. Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

b. Each applicant for a fuel-loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

Clarification

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver zeolite) for the following reasons:

a. The physical size of the auxiliary and/or fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

b. Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

c. Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

d. The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high-dose-rate areas.

After January 1, 1981, each applicant and licensee shall have the capability to remove the sampling cartridge to a low-background, low-contamination area for further analysis. Normally, counting rooms in auxiliary buildings will not have sufficiently low backgrounds for such analyses following an accident. In the low background area, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples under accident conditions. There should be sufficient samplers to sample all vital areas.

For applicants with fuel-loading dates prior to January 1, 1981, provide by fuel loading (until January 1, 1981) the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single-channel analyzer (SCA). The SCA window should be calibrated to the 365 KeV of iodine-131, using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

18.3.5.2 The Operating Agent Response

The Operating Agent provides iodine monitoring capability as specified in the following paragraphs.

During accident conditions, sampling cartridges removed from air samplers will be purged with air or nitrogen to remove noble gases. Purging will be done under an appropriate ventilation hood. Cartridges will then be taken to the counting room for isotopic analysis using a high purity Germanium detector and a multichannel analyzer to accurately determine the radioiodine concentrations. If, due to the accident conditions, the normal counting room is unavailable or unaccessible, an alternate low background counting room in the shop building will be used.

Depending upon the conditions at the time of sampling, the sample media may be charcoal or silver zeolite cartridges. The appropriate sample media will be determined on the basis of sampling environment and the efficiency of the media for collection of radiohalogens, particulates and noble gases.

Procedures are based on specific equipment purchased by the Operating Agent. A training program has been developed and includes the review of procedures and demonstration of methods by personnel responsible for air sample collection, preparation and counting/analysis to assure proficiency in determining radioiodine concentrations during accident and post-accident conditions.

18.3.5.3 Conclusion

See Section 18.3.1.3.

18.3.6 CONTROL ROOM HABITABILITY (III.D.3.4)

18.3.6.1 NRC Guidance Per NUREG-0737

In accordance with Task Action Plan Item III.D.3.4 and control room habitability, licensees shall ensure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design basis accident conditions (Criterion 19, "Control Room," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50).

Clarification

1. All licensees must make a submittal to the NRC regardless of whether or not they met the criteria of the referenced Standard Review Plans (SRP) sections. The new clarification specifies that licensees that meet the criteria of the SRPs should provide the basis for their conclusion that SRP 6.4 requirements are met. Licensees may establish this basis by referencing past submittals to the NRC and/or providing new or additional information to supplement past submittals.

2. All licensees with control rooms that meet the criteria of the following sections of the Standard Review Plan:

2.2.1-2.2.2	Identification of Potential Hazards in Site Vicinity,
2.2.3	Evaluation of Potential Accidents, and
6.4	Habitability System

shall report their findings regarding the specific SRP sections as explained below. The following documents should be used for guidance:

a. Regulatory Guide 1.78, "Assumptions for Evaluating the habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release;"

b. Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release;" and,

c. K. G. Murphy and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19," 13th AEC Air Cleaning Conference, August 1974.

Licensees shall submit the results of their findings as well as the basis for those findings by January 1, 1981. In providing the basis for the habitability finding, licensees may reference their past submittals. Licensees should, however, ensure that these submittals

reflect the current facility design and that the information requested in Attachment 1, to NUREG-0737, item III.D.3.4 is provided.

3. All licensees with control rooms that do not meet the criteria of the above-listed references, Standard Review Plans, Regulatory Guides, and other references.

These licensees shall perform the necessary evaluations and identify appropriate modifications.

Each licensee submittal shall include the results of the analyses of control room concentrations from postulated accidental release of toxic gases and control room operator radiation exposures from airborne radioactive material and direct radiation resulting from design-basis accidents. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either on the site or within 5 miles of the plant-site boundary. Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of control room habitability but is not all inclusive.

The design-basis-accident (DBA) radiation source term should be for the loss-of-coolant accident (LOCA) containment leakage and engineered safety feature (ESF) leakage contribution outside the containment, as described in Appendix A and B of Standard Review Plan Chapter 15.6.5. In addition, boiling-water reactor (BWR) facility evaluations should add any leakage from the main steam isolation valves (MSIV) (i.e., valve-stem leakage, valve seat leakage, main steam isolation valve leakage control system release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering the staff recommendations in Section D of Regulatory Guide 1.96 (Rev. 2) regarding MSIV leakage-control systems. Other DBAs should be reviewed to determine whether they might constitute a more-severe control room hazard than the LOCA.

In addition to the accident-analysis results, which should either identify the possible need for control room modifications or provide assurance that the habitability systems will operate under all postulated conditions to permit the control room operators to remain in the control room to take appropriate actions required by General Design Criterion 19, the licensee should submit sufficient information needed for an independent evaluation of the adequacy of the habitability systems. Attachment 1 lists the information that should be provided along with the licensee's evaluation.

18.3.6.2 The Operating Agent Response

The safety design bases for the habitability system for the control room are defined in Section 6.4. This section also discusses the applicable recommendations of Regulatory Guides 1.78, and 1.95. The results of dose calculations for a design basis loss-of-coolant accident release are presented in Section 15.6.5 and 15A.3.

The design of the habitability system for the control room envelope meets the appropriate recommendations of Regulatory Guide 1.78 and 1.95 and requirements of GDC-19.

18.3.6.3 Conclusion

The design of the control room habitability system meets the recommendations of item III.D.3.4 of NUREG-0737.

18.4 ENHANCEMENTS TO EMERGENCY PREPAREDNESS REGULATIONS

18.4.1 EMERGENCY FACILITIES AND EQUIPMENT

18.4.1.1 10CFR50, Appendix E, Section IV, E

Position

The NRC updated 10CFR50, Appendix E, Section IV, E, in 2011 providing revised requirements for emergency facilities and associated equipment.

18.4.1.2 The Operating Agent Compliance for EOF and Alternate TSC

The Operating Agent has constructed an off-site Emergency Operations Facility and Alternate Technical Support Center (TSC) whuch replaces previously existing facilities in compliance with 10CFR50, Appendix E, Section IV, E. The building facility is located approximately 11 miles northwest of the plant and approximately ¼ mile southwest of te intersection fo US Highway 75 and Interstate 35 (locally referred as BETO Junction). This building facility and its operation are intended to fully meet the requirements of the applicable regulations. Details of te facility are provided in the comprehensive emergency plan and applicable site procedures. The facility was declared operational prior to December 23, 2014, as required.

18.4.1.3 Conclusion

The Operating Agent has established an operational off-site EOF and Alternate TSC which meets requirements of the applicable regulations.

A0 APPENDIX A INTRODUCTION AND LICENSE RENEWAL COMMITMENTS

Introduction

This appendix provides the information submitted in an Updated Safety Analysis Report Supplement as required by 10 CFR 54.21(d) for the WCGS License Renewal application. Section A1 of this appendix contains summary descriptions of the programs used to manage the effects of aging during the period of extended operation. Section A2 contains summary descriptions of programs used for management of time-limited aging analyses during the period of extended operation. Section A3 contains evaluation summaries of Time Limited Aging Analyses (TLAAs) for the period of extended operation.

During the review of the WCGS Unit 1 license renewal application (LRA) by the staff of the NRC, WCNOC made commitments related to aging management programs to manage aging effects for structures and components. The following pages list these commitments.

A1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of License Renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. Sections A1 and A2 describe the programs and their implementation activities.

Three elements common to all aging management programs discussed in Sections A1 and A2 are corrective actions, confirmation process, and administrative controls. These elements are included in the WCNOC Quality Assurance (QA) Program, which implements the requirements of 10 CFR 50, Appendix B and are applicable to the safety-related and nonsafety-related systems, structures and components that are subject to aging management review activities.

A1.1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

ASME Section XI Inservice Inspection, Subsections IWB, IWC, & IWD inspections are performed to manage aging in Class 1, 2, and 3 piping and components within the scope of license renewal. The program includes periodic visual, surface, volumetric examinations and leakage tests of Class 1, 2 and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting. WCGS inspections meet ASME Section XI requirements and can manage aging such as cracking, surface and subsurface discontinuities, loss of material, loss of fracture toughness, and physical damage. The WCGS ISI Program is in accordance with 10 CFR 50.55a and ASME Section XI, 1998 edition through 2000 addenda.

A1.2 WATER CHEMISTRY

The Water Chemistry program includes maintenance of the chemical environment in the reactor coolant system and related auxiliary systems containing treated borated water and includes maintenance of the chemical environment in the steam generator secondary side and the secondary cycle systems to limit loss of material and cracking.

The Water Chemistry Program is based upon the EPRI primary and secondary water chemistry guidelines.

A1.3 REACTOR HEAD CLOSURE STUDS

The Reactor Head Closure Studs program includes periodic visual, surface, and volumetric examinations of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers and performs visual inspection of the reactor vessel flange closure during primary system leakage tests. The program implements ASME Section XI code, Subsection IWB, 1998 Edition through the 2000 addenda and detects reactor vessel stud, nut and washer cracking, loss of material due to wear and corrosion, and reactor coolant leakage from the reactor vessel flange.

A1.4 BORIC ACID CORROSION

The Boric Acid Corrosion program manages loss of material due to boric acid corrosion. The program includes provisions to identify, inspect, examine and evaluate leakage, and initiate corrective actions. The program relies in part on implementation of recommendations of NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR plants." Additionally, the program includes examinations conducted during ISI pressure tests performed in accordance with ASME Section XI requirements. The program addresses recent operating experience noted in NRC Regulatory Issue Summary 2003, "NRC Review of Responses to Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," (which includes NRC Bulletin 2002-01, 2002-02, and NRC Order EA-03-009).

Prior to the period of extended operation, procedures will be enhanced to state that susceptible components adjacent to potential leakage sources will include electrical components and connectors.

A1.5 NICKEL-ALLOY PENETRATION NOZZLES WELDED TO THE UPPER REACTOR VESSEL CLOSURE HEADS OF PRESSURIZED WATER REACTORS

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program manages cracking due to primary water stress corrosion cracking and loss of material due to boric acid wastage in nickel-alloy vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds. This program was developed in response to NRC Order EA-03-009 and was revised to comply with the requirements of ASME Code Case N-729-1 with conditions as published in 10CFR 50.55a.

Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and non-visual examination (underside of head) techniques. Procedures are developed to perform reactor vessel head bare metal inspections and calculations of the susceptibility ranking of the plant. Examinations are performed by Level II or III VT-2 certified personnel. Inspections completed to date have indicated no evidence of cracking in the vessel head penetration nozzles. Completed testing to date verifies that the inspection interval requirement is base metal visual inspections every third refueling outage or every five years, which ever is less and volumetric inspections every 8 calendar years or before RIV = 2.25 whichever is less.
Prior to the period of extended operation, procedures will be enhanced to indicate that if flaws attributed to PWSCC have been identified, whether acceptable or not for continued service under Paragraphs – 3130 or 3140 of ASME Code Case N-729-1, the re-inspection interval must be each refueling outage instead of the re-inspection intervals required by Table 1, Note (8) of ASME Code Case N-729-1, commencing from the same outage in which the flaw is detected.

A1.6 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion (FAC) program manages aging effects of wall thinning due to FAC on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phases).

The objectives of the FAC program are achieved by (a) identifying system components susceptible to FAC, (b) an analysis using a predictive code such as CHECWORKS to determine critical locations for inspection and evaluation, (c) providing guidance of follow-up inspections, (d) repairing or replacing components, as determined by the guidance provided by the program, and (e) continual evaluation and incorporation of the latest technologies, industry and plant in-house operating experience.

Procedures and methods used by the FAC program are consistent with WCGS commitments to NRC Bulletin 87-01, "Thinning of Pipe Wall in Nuclear Power Plants," and NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning."

A1.7 BOLTING INTEGRITY

The Bolting Integrity program manages the aging effects of cracking, loss of material, and loss of preload for pressure retaining bolting and ASME component support bolting. The program includes preload control, selection of bolting material, use of lubricants/sealants consistent with EPRI good bolting practices, and performance of periodic inspections for indication of aging techniques. The program also includes the inservice inspection requirements established in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF for ASME Class bolting.

WCGS good bolting practices are established in accordance with plant procedures. These procedures include requirements for proper disassembling, inspecting, and assembling of connections with threaded fasteners. The general practices that are established in this program are consistent with EPRI NP-5067, “Good Bolting Practices, Volume 1 and Volume 2,” and EPRI TR-104213, “Bolted Joint Maintenance and Applications Guide.”

A1.8 STEAM GENERATOR TUBE INTEGRITY

The Steam Generator Tube Integrity program includes the preventive measures, condition monitoring inspections, degradation assessment, repair and leakage monitoring activities necessary to manage cracking and loss of material. The aging management measures employed include non-destructive examination, visual inspection, sludge removal, tube plugging, in-situ pressure testing, maintaining the chemistry environment by removal of impurities and addition of chemicals to control pH and oxygen.

NDE inspection scope and frequency, and primary to secondary leak rate monitoring are conducted consistent with the requirements of WCGS Unit 1 Technical Specifications. Structural integrity limits consistent with Regulatory Guide 1.121, Revision 0, “Bases for Plugging Degraded PWR Steam Generator Tubes,” are applied. Steam generator management practices are consistent with NEI 97-06 “Steam Generator Program Guidelines”. Program deviations from NEI 97-06 are prepared and approved in accordance with NEI 97-06 and EPRI steam generator management program guidance.

A1.9 OPEN-CYCLE COOLING WATER SYSTEM

The Open-Cycle Cooling Water (OCCW) System program manages loss of material and reduction of heat transfer for components exposed to raw water. The program includes chemical treatment and control of biofouling; heat exchanger performance testing; and periodic inspections to ensure that the effects of aging will be managed on the OCCW systems or structures and components serviced by the OCCW systems for the period of extended operation. The program is consistent with commitments as established in WCGS responses to NRC Generic Letter 89-13 "Service Water System Problems Affecting Safety-Related Components."

The Open-Cycle Cooling Water System program provides the general requirements for implementation and maintenance of programs and activities which mitigate aging of OCCW systems and components. The various aspects of the WCGS program (control, monitoring, maintenance and inspections) are implemented in station procedures.

A1.10 CLOSED-CYCLE COOLING WATER SYSTEM

The Closed-Cycle Cooling Water System Program manages loss of material, cracking, and reduction in heat transfer for components in closed cycle cooling water systems. The program includes maintenance of system corrosion inhibitor concentrations and chemistry parameters following the guidance of EPRI TR-107396 to minimize aging, and periodic testing and inspections to evaluate system and component performance. Inspection methods include visual, ultrasonic testing (UT) and eddy current testing (ECT).

Prior to the period of extended operation, a new periodic preventive maintenance activity will be developed to specify performing inspections of the internal surfaces of valve bodies and accessible piping while the valves are disassembled for operational readiness inspections to detect loss of material and fouling. The acceptance criteria will be specified in this preventive maintenance activity. In addition, visual inspection procedures used for identification of stress corrosion cracking will be enhanced to define cracking, provide additional guidance for detection of cracking and identify specific acceptance criteria relating to "as-found" cracking.

A1.11 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program manages the loss of material due to corrosion and the effects of rail wear for all cranes, trolley structural components and applicable rails within the scope of license renewal. The program is implemented through periodic visual inspections of components.

Crane inspection activities verify structural integrity of the crane components required to maintain the crane intended function. Visual inspections assess conditions such as loss of material due to corrosion of structural members, misalignment, flaking, side wear of rails, loose tie down bolts and excessive wear or deformation of monorails. The inspection requirements are consistent with the guidance provided by NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" for load handling systems that handle heavy loads which can directly or indirectly cause a release of radioactive material, applicable industry standards (such as CMAA Spec 70 and ANSI B30.11) for other cranes within the scope of license renewal, and applicable OSHA regulations (such as 29 CFR Volume XVII, Part 1910 and Section 1910.179).

Prior to the period of extended operation, procedures will be enhanced to identify industry standards or WCGS specifications that are applicable to the component and to specifically inspect for loss of material due to corrosion or rail wear.

A1.12 FIRE PROTECTION

The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pump, and the halon fire suppression system, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, hardness and shrinkage due to weathering of fire barrier penetration seals, and hardness – loss of strength for halon fire suppression system flexible hoses. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed. The internal surface of the diesel-driven fire pump fuel oil supply line is managed by the Fuel Oil Chemistry program (A1.14), which utilizes the One-Time Inspection program (A1.16) to verify the effectiveness of the Fuel Oil Chemistry program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function due to aging of the fuel oil supply line.

Drop tests on approximately 10 percent of accessible horizontal and vertical fire dampers are performed on an 18 month basis. Fire dampers that are inaccessible for drop testing are visually inspected to assess integrity/availability. Visual inspections are performed on fire-rated doors at least once per year to verify the integrity of door surfaces and for clearances to detect aging of the fire doors. A visual inspection and function test of the halon fire suppression system is performed every 18 months. Approximately 10 percent of each type (electrical and mechanical as practical) of penetration seal is visually inspected at least once every 18 months. Fire barrier walls, ceilings, and floors including coatings and wraps (structural steel fireproofing, raceway fire wrap and hatch covers) are visually inspected at least once every 18 months.

Prior to the period of extended operation, fire damper inspection and drop test procedures will be enhanced to inspect damper housing for signs of corrosion and to specify fire barriers and doors described in USAR Appendix 9.5A, "WCGS Fire Protection Comparison to APCSB 9.5-1 Appendix A," and WCGS Fire Hazards Analysis. Training for technicians performing the fire door and fire damper visual inspections will be enhanced to include fire protection inspection requirements and training documentation.

Prior to the period of extended of operation, halon fire suppression system inspection procedures will be enhanced to include visual inspection of halon tank flexible hoses for hardening - loss of strength. Visual inspections would not be required for flexible hoses that have scheduled periodic replacement intervals.

A1.13 FIRE WATER SYSTEM

The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests are performed considering applicable National Fire Protection Association (NFPA) codes and standards. Nuclear Electric Insurance Limited (NEIL) performance based guidance is utilized for fire protection system inspection, testing, and maintenance intervals. The fire water system discharge pressure is continuously monitored such that loss of system pressure is immediately detected and corrective actions are initiated. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler head to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25, 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of aging are detected in a timely manner. Visual inspections of the fire protection system exposed to water, evaluating wall thickness to identify evidence of loss of material due to corrosion, are covered by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (A1.22).

A1.14 FUEL OIL CHEMISTRY

The Fuel Oil Chemistry program manages loss of material on the internal surface of components in the emergency diesel fuel oil storage and transfer system and diesel fire pump fuel oil system. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) visual inspection of internal surfaces during periodic draining and cleaning of fuel oil tanks in the emergency diesel fuel oil storage and transfer system, (d) ultrasonic wall thickness measurements from external surfaces of fuel oil tanks, (e) one-time ultrasonic (UT) or pulsed eddy current (PEC) thickness examination on the external surface of the diesel fire pump fuel oil tank, (f) inspection of new fuel oil before it is introduced into the storage tanks, and (g) one-time inspections of a representative sample of components in systems that contain fuel oil by the One-Time Inspection program.

Prior to the period of extended operation, the emergency fuel oil day tanks will be added to the ten year drain, clean, and internal inspection program. Procedures will be enhanced to provide for supplemental ultrasonic thickness measurements if there are indications of reduced cross sectional thickness found during the visual inspection of the emergency fuel oil storage tanks.

A1.15 Reactor Vessel Surveillance

The Reactor Vessel Surveillance program is consistent with ASTM E 185. Actual reactor vessel coupons are used, but an exemption in the original license permits use of other than beltline weld material for the weld coupons. The surveillance coupons are tested by a qualified offsite vendor, to its procedures. The testing program and reporting conform to requirements of 10 CFR 50 Appendix H.

The schedule has been revised by removal of the last two coupon sets to the spent fuel pool, at exposures greater than those expected at the beltline wall at 60 years. This withdrawal therefore meets the ASTM E 185-82 criterion which states that capsules may be removed when the capsule neutron fluence is between one and two times the limiting fluence calculated for the vessel at the end of expected life. Vessel fluence is now determined by ex-vessel dosimetry. This schedule change has been approved by the NRC, as required by 10 CFR 50 Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

A1.16 ONE-TIME INSPECTION

The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (A1.2), Fuel Oil Chemistry program (A1.14), and Lubricating Oil Analysis program (A1.23). The aging effects to be evaluated by the One-Time Inspection program are loss of material, cracking, and reduction of heat transfer. The One-Time Inspection program determines non-destructive examination (NDE) sample size for each material-environment group using established statistical methodologies and selects piping/component inspection locations within the sample that are based on service period, operating conditions, and design margins. The One-Time Inspection program specifies corrective actions and increased sampling of components if aging effects are found.

This new program will be implemented and completed within the ten year period prior to the period of extended operation.

A1.17 Selective Leaching of Materials

The Selective Leaching of Materials program manages the loss of material due to selective leaching for brass (>15% zinc) and gray cast iron components exposed to raw water or closed-cycle cooling water within the scope of license renewal. The Selective Leaching of Materials program is in addition to the Open Cycle Cooling Water program and the Closed Cycle Cooling Water program in these cases.

The program includes a one-time inspection (visual and mechanical methods) of a selected sample of component internal surfaces to determine whether loss of material due to selective leaching is occurring. If indications of selective leaching are confirmed, follow up examinations or evaluations are performed.

The Selective Leaching of Materials program is a new program that will be implemented prior to the period of extended operation.

A1.18 BURIED PIPING AND TANKS INSPECTION

The Buried Piping and Tanks Inspection program manages loss of material of buried components in the essential service water system, emergency diesel engine fuel oil storage and transfer system, auxiliary feedwater system, high pressure coolant injection system (borated refueling water storage system), and the fire protection system. Visual inspections monitor the condition of protective coatings and wrappings found on carbon steel, gray cast iron or ductile iron components and assess the condition of stainless steel components with no protective coatings or wraps. The program includes opportunistic inspection of buried piping and tanks as they are excavated or on a planned basis if opportunistic inspections have not occurred.

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended of operation. Within the ten year period prior to entering the period of extended operation, an opportunistic or planned inspection will be performed. Upon entering the period of extended operation a planned inspection within ten years will be required unless an opportunistic inspection has occurred within this ten year period.

A1.19 ONE-TIME INSPECTION OF ASME CODE CLASS 1 SMALL-BORE PIPING

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of stainless steel ASME Code Class 1 piping less than or equal to 4 inches. This program is a part of the WCGS Risk-Informed Inservice Inspection (RI-ISI) program.

For ASME Code Class 1 small-bore piping, the RI-ISI program requires volumetric examinations (by ultrasonic testing) on selected weld locations to detect cracking. Weld locations are selected based on the guidelines provided in EPRI TR-112657. Ultrasonic examinations are conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3131 and IWB-2430. The fourth interval of the ISI program at WCGS will provide the results for the one time inspection of ASME Code Class 1 small-bore piping.

A1.20 EXTERNAL SURFACES MONITORING PROGRAM

The External Surfaces Monitoring Program manages loss of material for external surfaces of steel components and hardening and loss of strength for elastomers in ventilation and mechanical systems. The External Surfaces Monitoring Program consists of periodic visual inspections for aging management of loss of material, leakage, elastomer hardening and loss of strength.

Loss of material for external surfaces is managed by the Boric Acid Corrosion program (A1.4) for components in a system with treated borated water or reactor coolant environment on which boric acid corrosion may occur, Buried Piping and Tanks Inspection program (A1.18) for buried components, and Structures Monitoring Program (A1.32) for supports, structural items, and electrical components.

A1.21 FLUX THIMBLE TUBE INSPECTION

The Flux Thimble Tube Inspection program performs wall thickness eddy current testing of all flux thimble tubes that form part of the reactor coolant system pressure boundary. The pressure boundary includes the length of the tube inside the reactor out to the seal fittings outside the reactor vessel. Eddy current testing is performed on the portion of the tubes inside the reactor vessel. The program implements the recommendations of NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.”

During each outage, flux thimble tube wear is evaluated and inspections are performed based on evaluation results. Wall thickness measurements are trended and wear rates are calculated. If the predicted wear (as a measure of percent through wall) for a given flux thimble tube is projected to exceed the established acceptance criteria prior to the next outage, corrective actions are taken to reposition, cap or replace the tube.

A1.22 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, loss of material and hardening - loss of strength. Visual inspections of the internal surfaces of piping, piping components, ducting and other components that are not covered by other aging management programs is included in this program.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses the work control process to conduct and document inspections. The program performs visual inspections during periodic maintenance, predictive maintenance, surveillance testing and corrective maintenance to detect aging effects that could result in a loss of component intended function. For those systems or components where inspections of opportunity are insufficient, an inspection will be conducted prior to the period of extended operation to provide reasonable assurance that the intended functions are maintained.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented prior to the period of extended operation.

A1.23 LUBRICATING OIL ANALYSIS

The Lubricating Oil Analysis program manages loss of material and reduction of heat transfer for components within the scope of license renewal. The program maintains lubricating oil contaminants within acceptable limits, thereby preserving an environment that is not conducive to aging effects and includes acceptance criteria based on industry guidelines for oil chemical and physical properties, wear metals, contaminants, additives, and water. Increased impurities and degradation of oil properties provide an indication of aging of materials exposed to lubricating oil.

Additionally, ferrography is performed on oil samples for trending of wear particle concentrations for the reactor coolant pumps upper and lower bearing oil and other components. Monitoring and trending of lubricating oil analysis results identifies component aging prior to loss of component intended function.

A1.24 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the aging effects of embrittlement, melting, cracking, swelling, surface contamination, or discoloration to ensure that electrical cables and connections not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended functions.

Non-EQ cables and connections within the scope of license renewal in accessible areas with an adverse localized environment are inspected. The inspections of Non-EQ cables and connectors in accessible areas are representative, with reasonable assurance, of cables and connections in inaccessible areas with an adverse localized environment. At least once every ten years, the Non-EQ cables and connections within the scope of license renewal in accessible areas are visually inspected for embrittlement, melting, cracking, swelling, surface contamination, or discoloration.

The acceptance criterion for visual inspection of accessible Non-EQ cable jacket and connection insulating material is the absence of anomalous indications that are signs of degradation. Corrective actions for conditions that are adverse to quality are performed in accordance with the corrective action program as part of the QA program.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation.

A1.25 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

The scope of this program includes the cables and connections used in sensitive instrumentation circuits with sensitive, high voltage low-level signals within the Ex-core Neutron Monitoring System including the source range, intermediate range, and power range monitors.

This program provides reasonable assurance that the intended function of cables and connections used in instrumentation circuits with sensitive, low-level signals that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture are maintained consistent with the current licensing basis through the period of extended operation. In most areas, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment for those areas.

Calibration surveillance tests are used to manage the aging of the cable insulation and connections so that instrumentation circuits perform their intended functions. When an instrumentation channel is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable and connections. A review of calibration results will be completed prior to the period of extended operation and every 10 years thereafter.

A1.26 INACCESSIBLE MEDIUM VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program manages the aging effects of inaccessible medium voltage cables within the scope of license renewal exposed to adverse localized environments caused by significant moisture simultaneously with significant voltage.

All cable manholes that contain in-scope Non-EQ inaccessible medium voltage cables will be inspected for water collection. Collected water will be removed as required. This inspection and water removal will be performed based on actual plant experience with the inspection frequency being at least once every two years for electrical manholes without sump pumps and with the inspection frequency being at least once every five years for electrical manholes with sump pumps.

The program provides for testing of in-scope Non-EQ inaccessible medium voltage cables to provide an indication of the conductor insulation condition. At least once every ten years, a polarization index test as described in EPRI TR-103834-P1-2 or other testing that is state-of-the-art at the time of the testing is performed.

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program is a new program that will be implemented prior to the period of extended operation.

A1.27 ASME SECTION XI, SUBSECTION IWE

The ASME Section XI, Subsection IWE containment inservice inspection program provides aging management of the steel liner of the concrete containment building, including the containment liner plate, piping and electrical penetrations, access hatches, and the fuel transfer tube. Inspections are performed to identify and manage any containment liner aging effects that could result in loss of intended function. Acceptance criteria for components subject to Subsection IWE exam requirements are specified in Article IWE-3000. In conformance with 10 CFR 50.55a(g)(4)(ii), the WCGS CISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

A1.28 ASME SECTION XI, SUBSECTION IWL

The ASME Section XI, Subsection IWL containment inservice inspection program manages aging of the concrete containment structure (including the tendon gallery ceiling), the concrete dome, and the post-tensioning system. Inspections are performed to identify and manage any containment concrete aging effects that could result in loss of intended function. In conformance with 10 CFR 50.55a(g)(4)(ii), the WCGS ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

Prior to the period of extended operation, procedures will be enhanced to include two new provisions regarding inspection of repair/replacement activities.

A1.29 ASME SECTION XI, SUBSECTION IWF

The ASME Section XI, Subsection IWF program manages aging effects that could result in loss of intended function for Class 1, 2 and 3 component supports. There are no Class MC supports at WCGS. In conformance with 10 CFR 50.55a(g)(4)(ii), the WCGS ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

A1.30 10 CFR 50, APPENDIX J

The 10 CFR Part 50, Appendix J program monitors leakage rates through the containment pressure boundary, including the penetrations and access openings, in order to detect degradation of containment pressure boundary. Seals, gaskets, and bolted connections are also monitored under the program.

Containment leak rate tests are performed in accordance with 10 CFR 50 Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors" Option B; Regulatory Guide 1.163, Revision 0, "Performance-Based Containment Leak-Testing Program," NEI 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J; and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

Containment leak rate tests are performed to assure that leakage through the primary containment, and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. Corrective actions are taken if leakage rates exceed established administrative limits for individual penetrations or the overall containment pressure boundary.

A1.31 MASONRY WALL PROGRAM

The Masonry Wall Program, which is part of the Structures Monitoring Program, manages aging of masonry walls, and structural steel restraint systems of the masonry walls, within scope of license renewal based on guidance provided in IE Bulletin 80-11, "Masonry Wall Design" and NRC Information Notice 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to NRC IE Bulletin 80-11." The Masonry Wall Program contains inspection guidelines and lists attributes that cause aging of masonry walls, which are to be monitored during structural monitoring inspections, as well as establishes examination criteria, evaluation requirements, and acceptance criteria.

Prior to the period of extended operation, procedures will be enhanced to identify unreinforced masonry in the radwaste building within the scope of license renewal that requires aging management.

A1.32 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program manages the cracking, loss of material, and change in material properties by monitoring the condition of structures and structural supports that are within the scope of license renewal. The Structures Monitoring Program implements the requirements of 10 CFR 50.65 and is consistent with the guidance of NUMARC 93-01, Revision 2 and Regulatory Guide 1.160, Revision 2.

The Structures Monitoring Program provides inspection guidelines and walkdown checklists for concrete elements, structural steel, masonry walls, treated wood, structural features (e.g., caulking, sealants, roofs, etc.), structural supports, and miscellaneous components such as doors. The Structures Monitoring Program includes all masonry walls within the scope of license renewal. The Structures Monitoring Program also inspects supports for equipment, piping, conduit, cable tray, HVAC, and instrument components. The Structures Monitoring Program monitors groundwater for pH, sulfates, and chlorides.

Prior to the period of extended operation, procedures will be enhanced to add inspection parameters for treated wood, to add the disconnect enclosure and foundation in the switchyard, and to monitor groundwater for pH, sulfates, and chlorides. Two samples of groundwater will be tested every five years.

A1.33 RG 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

The Regulatory Guide 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants program manages aging due to extreme environmental conditions and the effects of natural phenomena that may affect water-control structures. WCGS meets the recommendations of Regulatory Guide 1.127, Revision 1.

This program includes inspection and surveillance activities for dams, slopes, canals, and other water-control structures associated with emergency cooling water systems or flood protection.

The program includes periodic visual inspections of in-scope concrete structures, periodic monitoring of the hydraulic and structural condition of the Ultimate Heat Sink (UHS), as well as associated structures, main dam service spillway, and auxiliary spillway, periodic dredging of the UHS reservoir and channel connecting the reservoir to the essential service water pumphouse, and survey of the UHS dam for vertical movement.

Prior to the period of extended operation, procedures will be enhanced so that the main dam service spillway and the auxiliary spillway will be inspected in accordance with the same specification, to clarify the scope of inspections for the spillways, to add the 5 year inspection frequency for the main dam service spillway, and to add cavitation to the list of concrete aging effects for surfaces other than spillways.

A1.34 NICKEL ALLOY AGING MANAGEMENT PROGRAM

The Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking in all plant locations that contain Alloy 600, with the exception of steam generator tubing (aging management of steam generator tubing is performed by the Steam Generator Tubing Integrity program (B2.1.8)). Aging management requirements for nickel alloy penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (B2.1.5) are included here for review convenience. This includes reactor coolant system (RCS) pressure boundary, RCS non-pressure boundary, and ESF locations.

The Nickel Alloy Aging Management Program uses inspections, mitigation techniques, repair/replace activities and monitoring of operating experience to manage the aging of Alloy 600 at WCGS. Detection of indications is accomplished through a variety of examinations consistent with ASME Section XI Subsections IWB and IWC, and ASME Code Cases N-729-1, N-770-1 & N-722-1 with conditions as published in 10 CFR 50.55(a).

Mitigation techniques are implemented when appropriate to preemptively remove conditions that contribute to primary water stress corrosion cracking. Repair/replacement activities are performed to proactively remove or overlay Alloy 600 material, or as a corrective measure in response to an unacceptable flaw in the material.

The Wolf Creek Nickel Alloy Aging Management Program will be supplemented with implementation of applicable (1) ASME Code Cases N-729-1, N-770-1 & N-722-1 with conditions as published in 10 CFR 50.55 (a) and (2) staff-accepted industry guidelines, and (3) participation in industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel alloys, (4) upon completion of these programs, but not less than 24 months before entering the period of extended operation, WCNOC will submit an inspection plan for reactor coolant system nickel alloy pressure boundary components to the NRC for review and approval.

A1.35 REACTOR COOLANT SYSTEM SUPPLEMENT

Section 3.1 of NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," supplements the aging management programs for the reactor coolant system components with the following additional requirements.

WCNOC will:

A. Reactor Coolant System Nickel Alloy Pressure Boundary Components

Implement applicable (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines, (3) participate in the industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel alloys, (4) upon completion of these programs, but not less than 24 months before entering the period of extended operation, WCNOC will submit an inspection plan for reactor coolant system nickel alloy pressure boundary components to the NRC for review and approval, and

B. Reactor Vessel Internals

(1) Participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, WCNOC will submit an inspection plan for reactor internals to the NRC for review and approval.

A1.36 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the effects of loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. A representative sample of electrical cable connections not subject to 10 CFR 50.49 environmental qualification requirements within the scope of license renewal is infrared thermography tested as part of the WCGS predictive maintenance. The sample is based upon application, circuit loading and environment. Infrared thermography testing is being performed at least once every 10 years.

Prior to the period of extended operation, the infrared thermography testing procedure will be enhanced to require an engineering evaluation when test acceptance criteria are not met. The evaluation will include identifying the extent of condition, the potential root cause for not meeting the test acceptance criteria, and the likelihood of recurrence.

A one-time inspection of a representative sample of low voltage low current or low load connections will be performed prior to the period of extended operation. The technical basis for the selected sample will be documented and based upon application (low voltage), circuit loading (low current or low load), and environment (plant indoor air and outdoor air). An engineering evaluation will be performed when test acceptance criteria are not met. The evaluation will include identifying the extent of condition, the potential root cause for not meeting the test acceptance criteria, the likelihood of recurrence and the need to expand the sample size and/or frequency of the inspection.

A2 SUMMARY DESCRIPTIONS OF TIME-LIMITED AGING ANALYSIS AGING MANAGEMENT PROGRAMS

A2.1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

The WCGS Metal Fatigue of the Reactor Coolant Pressure Boundary program ensures that actual plant experience remains bounded by the assumptions used in the deesign calculations, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means. The more-recent fatigue monitoring results indicate that none of the design transients should occur more than the currently-specified number of times before the end of a 60-year period of extended operation, and that fatigue usage factors should remain below the code allowable limit of 1.0, including effects of the reactor coolant environment as described by NUREG/CR-6260.

Prior to the period of extended operation, the Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include:

- A cycle count action limit and corrective actions. An action limit will be established that requires corrective action when the cycle count for any of the critical thermal and pressure transients is projected to reach a stated percentage of the design-specified number of cycles before the end of the next fuel cycle. If this action limit is reached, acceptable corrective actions include:

  1. Review of fatigue usage calculations
     - To determine whether the transient in question contributes significantly to CUF.
     - To identify the components and analyses that are affected by the transient in question.
     - To ensure that the analytical bases of the leak-before-break (LBB) fatigue crack propagation analysis and of the high-energy line break (HELB) locations are maintained.

  2. Evaluation of remaining margins on CUF based on cycle-based or stress-based CUF calculations using the WCGS fatigue management program software.

3. Redefinition of the specified number of cycles (e.g., by reducing specified numbers of cycles for other transients and using the margin to increase the allowed number of cycles for the transient that is approaching its specified number of cycles).

- A cumulative fatigue usage action limit and corrective actions. An action limit will be established that requires corrective action when calculated CUF (from cycle-based or stress-based monitoring) for any monitored location is projected to reach 1.0 within the next 2 or 3 fuel cycles. If this action limit is reached acceptable corrective actions include:

    1. Determine whether the scope of the monitoring program must be enlarged to include additional affected reactor coolant pressure boundary locations. This determination will ensure that other locations do not approach design limits without an appropriate action.

    2. Enhance fatigue monitoring to confirm continued conformance to the code limit.

    3. Repair the component.

    4. Replace the component.

    5. Perform a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded.

    6. Modify plant operating practices to reduce the fatigue usage accumulation rate.

    7. Perform a flaw tolerance evaluation and impose component-specific inspections, under ASME Section XI Appendices A or C (or their successors), and obtain required approvals by the NRC.

- These corrective actions are equally applicable to the WCGS NUREG/CR-6260 locations described in Section A3.2.3, “Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components,” including consideration of the effects of the reactor coolant environment.

- 10 CFR 50 Appendix B procedural and record requirements.
- Validation of the presence of absence of charging nozzle thermal sleeves. If sleeves are not present, the fatigue monitoring program analysis for the charging nozzle will be re-performed.
- A fatigue monitoring program updated baseline for the pressurizer hot leg surge nozzle based on the additional insurge/outsurge cycles accumulated in a pre-MOP environment. Additionally, the fatigue monitoring program baseline for the charging nozzles will be updated with consideration for the differential contribution of fatigue for each category of charging event.

A2.2 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL COMPONENTS

The Environmental Qualification (EQ) of Electrical Components program manages component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. The Environmental Qualification (EQ) of Electrical Components program is consistent with the requirements of 10 CFR 50.49, and the guidance of NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment” and Regulatory Guide 1.89, “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants”, Revision 1 for maintaining qualification of equipment.

A2.3 CONCRETE CONTAINMENT TENDON PRESTRESS

The Concrete Containment Tendon Prestress program, within the WCGS Creek ASME Section XI Subsection IWL Program, manages the loss of tendon prestress in the post-tensioning system.

The WCGS post-tensioning system consists of inverted U-shaped tendons, extending up through the basemat, through the full height of the cylindrical walls and over the dome; and horizontal circumferential (hoop) tendons, at intervals from the basemat to about the 45-degree elevation of the dome. The basemat is conventionally reinforced. The tendons are ungrouted, in grease-filled glands.

Prior to the period of extended operation, procedures will be revised to extend the list of surveillance tendons to include random samples for the 40, 45, 50, and 55 year surveillances, to explicitly require a regression analysis for each tendon group after every surveillance; and to invoke and describe regression analysis methods used to construct the lift-off trend lines. Surveillance program predicted force lines for the vertical and hoop tendon groups will be extended to 60 years. Procedure descriptions of acceptance criteria action levels will be revised to conform to the ASME Code, Subsection IWL 3221 descriptions.

A3 EVALUATION SUMMARIES OF TIME-LIMITED AGING ANALYSES

10 CFR 54.21(c) requires that an applicant for a renewed license identify time-limited aging analyses (TLAAs) and evaluate them for the period of extended operation. The following TLAAs have been identified and evaluated for WCGS.

A3.1 REACTOR VESSEL NEUTRON EMBRITTLEMENT

Ferritic materials of the reactor vessel are subject to embrittlement (loss of fracture toughness) due to high-energy neutron exposure. The following predictions of neutron fluence and of its embrittlement effects are TLAAs:

- Neutron Fluence, Upper Shelf Energy, Adjusted Reference Temperature (Fluence, USE, and ART)
- Pressurized Thermal Shock (PTS)
- Reactor Vessel Thermal Limit Analysis and Pressure-Temperature (P-T) Limits
- Low Temperature Overpressure Protection (LTOP)

The Reactor Vessel Surveillance program is described in Section A1.15.

A3.1.1 Neutron Fluence, Upper Shelf Energy and Adjusted Reference Temperature (Fluence, USE, and ART)

<u>Fluence</u>

Neutron embrittlement depends on lifetime fluence of neutrons with energies greater than 1 MeV. The original design basis estimate for expected end-of-life fluence has been increased to account for increased unit rating and for increased plant capacity factors, but also reduced for low-leakage core loadings.

WCGS has evaluated projected fluences and their uncertainties based on the guidance of Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” Revision 0. The ¼-t and ¾-t fluences in the vessel wall were also projected consistent with Regulatory Guide 1.99, “Radiation Damage to Reactor Vessel Materials," Revision 2, Section 1.1, Equation 3, attenuation. The evaluation also projected the alternative displacements-per-iron atom (dpa) measure of embrittlement to 54 EFPY using methods consistent with ASTM E853 and E693, in support of dpa assessments consistent with Regulatory Guide 1.99, Revision 2.

Since the W and Z coupon exposure has now exceeded that expected at the end of the extended period of operation, these capsules have been removed to the spent fuel pool, and vessel neutron fluence is now confirmed by ex-vessel dosimetry.

USE and ART

For reactor vessel materials, 10 CFR 50 Appendix G requires the predicted end-of-life Charpy impact test upper-shelf absorbed energy (USE) to be at least 50 ft-lb, unless an approved analysis supports a lower value. The 60 year end-of-life USE and adjusted reference temperature (ART) of the limiting material was confirmed from test of the X-capsule coupons, with exposures nearly equal to the projected 54 EFPY, 60-year vessel wall fluence. The examination methods were consistent with 10 CFR 50 Appendices G and H, ASTM E185-82, and Westinghouse procedures. The X-coupon analysis demonstrates more-than-adequate EOL USE, and indicates that ART for the limiting material will remain modest and will permit adequate operating margins to P-T limits until the end of a 60-year period of extended operation. See Section A3.1.3 for P-T limits.

A3.1.2 Pressurized Thermal Shock (PTS)

If the reference temperature for pressurized thermal shock (RT_{PTS}) for each heat of material of the reactor pressure vessel does not exceed 270 °F for plates, forgings, and axial welds; or 300 °F for circumferential welds (the PTS screening criteria), only the reactor pressure vessel is "relied on to demonstrate compliance" with the 10 CFR 50.61 PTS rule. RT_{PTS} for the limiting material has been projected to remain well below its screening criterion until the end of a 60-year period of extended operation. The reactor pressure vessel therefore meets the PTS screening criteria and will continue to do so for the period of extended operation. Therefore no safety analysis by Regulatory Guide 1.154, "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," Revision 0, alternative methods is required, and the vessel is therefore the only component relied upon to demonstrate compliance with 10 CFR 50.61 throughout the period of extended operation.

A3.1.3 Pressure-Temperature (P-T) Limits

10 CFR 50 Appendix G requires a reactor vessel thermal limit analysis to determine operating pressure-temperature limits for heatup, cooldown, criticality, and inservice leakage and hydrostatic testing. The resulting P-T limit curves are operating limits, conditions of the operating license, and are included in the *Pressure and Temperature Limits Report* (PTLR), as required by Technical Specifications.

Because of the relationship between the operating pressure-temperature limits and the fracture toughness transition of the reactor vessel, the thermal limits analysis is valid only up to a stated vessel fluence limit. The currently-applicable PTLR is valid up to 54 EFPY.

A3.1.4 Low Temperature Overpressure Protection (LTOP)

LTOP is required by Technical Specifications and is provided (in part) by the cold overpressurization mitigation system (COMS), which opens the power-operated relief valves at a setpoint determined by the currently-applicable pressure-temperature limits analysis.

The COMS setpoint is established in the *Pressure and Temperature Limits Report* (PTLR), Section A3.1.3.

A3.2 METAL FATIGUE

This section describes:

- ASME Section III Class 1 Fatigue Analysis of Vessels, Piping, and Components

- ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure
  Vessel Internals

- Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190

- Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in B31.1 and ASME Section III Class 2 and 3 Piping

- Fatigue Design of Spent Fuel Pool Liner and Racks for Seismic Events

- Fatigue Design and Analysis of Class IE Electrical Raceway Support Angle Fittings for Seismic Events

At WCGS, no vessels, heat exchangers, or pumps were designed to ASME Section III Class 2 or 3, or ASME VIII Division 2 rules that required design for a stated number of load cycles.

Basis of Fatigue Analyses

ASME Section III Class 1 design specifications define a design basis set of static and transient load conditions. The design number of each transient was selected to be somewhat larger than expected to occur during the 40-year licensed life of the plant, based on operating experience, and on projections of future operation based on innovations in the system designs. Although original design specifications commonly state that the transients are for a 40-year design life, the fatigue analyses themselves are based on the specified number of occurrences of each transient rather than on this lifetime.

Fatigue Management Program

The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 will ensure that actual plant experience remains bounded by the assumptions used in the design calculations, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means. The more-recent fatigue monitoring cycle counts indicate that none of the design transients will occur more than the currently-specified number of times before the end of a 60-year period of extended operation, and consequently, that the fatigue analysis TLAAs based on those transients will remain valid for the period of extended operation.

A3.2.1 ASME Section III Class 1 Fatigue Analysis of Vessels, Piping, and Components

Fatigue analyses exist for ASME Section III Division 1 Class 1 piping, vessels, steam generators, pumps, and valves. The reactor vessel internals are not designed to ASME Section III Class 1 but are analyzed to ASME Section III Subsection NG. See Section A3.2.2.

A3.2.1.1 Reactor Pressure Vessel, Nozzles, Head, and Studs

The WCGS reactor vessel is designed to ASME Section III, Subsection NB (Class 1), 1971 Edition with addenda through Winter 1972. The analysis has been updated to incorporate redefinitions of loads and design basis events, operating changes, power rerate and T_{hot} reduction, minor modifications, and possible operating contingencies.

See Section A3.2.1.9 for the evaluation of certain noise events affecting the fatigue analyses of the primary coolant system and reactor vessel.

The reactor vessel primary coolant inlet and outlet nozzles and lower-head-to-shell juncture are evaluated for effects of the reactor coolant environment on fatigue behavior of these materials, consistent with the guidance of NUREG/CR-06260. See Section A3.2.3 of this document.

Fatigue usage factors in the reactor vessel pressure boundary do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events, principally on startup and shutdown transients and on boltup. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 ensures that the fatigue usage factors based on those transients will remain within the code limit of 1.0 for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.2 Control Rod Drive Mechanism (CRDM) Pressure Housings, Adapter Plugs, and Canopy Seals

The CRDM housings are designed to ASME Section III, Subsection NB (Class 1), 1974 Edition with addenda through Winter 1974. The analysis of pressure-retaining components was reexamined for the power rerate and T_{hot} reduction modification, and for addition of canopy seal clamp assemblies. The fatigue usage factors for the CRDM pressure housings, adapter plugs, and canopy seals have been evaluated and projected to remain below the ASME Code allowable of 1.0 for 60 years.

A3.2.1.3 Reactor Coolant Pump Pressure Boundary Components

The pump pressure boundary was designed to ASME Section III, 1971 edition with addenda through Summer 1973. Subarticle NB-3400, "Design of Class 1 Pumps," of this edition and addenda, does not require a fatigue analysis, but the nuclear steam supply vendor specified a fatigue analysis. Low stresses permitted a fatigue waiver analysis for many pump components. These fatigue and fatigue waiver analyses have been updated to incorporate redefinitions of loads and design basis events, operating changes, power rerate, and minor modifications.

Fatigue usage factors in the reactor coolant pumps do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events, principally on startup and shutdown transients. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 will ensure that the fatigue usage factors based on those transients will remain within the code limit of 1.0 for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.4 Pressurizer and Pressurizer Nozzles

The WCGS pressurizer is designed to ASME Section III, Subsection NB (Class 1), 1974 Edition. The analysis has been updated from time to time to incorporate redefinitions of loads and design basis events, operating changes, power rerate and T_{hot} reduction, and minor modifications; including the effects of thermal stratification in the lower head, surge nozzle, and surge line discussed in NRC Bulletin 88-11.

The pressurizer surge nozzle and lower head may be subject to significant operating thermal stress cycles due to thermal stratification and insurge-outsurge cycles, and are therefore expected to be the limiting pressurizer components for fatigue. The fatigue usage factors of these locations are specifically monitored. The expected usage factors in these locations should be acceptable for 60 years of operation.

With the exception of thermal stratification effects in the surge nozzle, fatigue usage factors in the pressurizer pressure boundary and support components do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 will ensure that the fatigue usage factors based on those transients will remain within the code limit of 1.0 for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.5 Steam Generator ASME Section III Class 1, Class 2 Secondary Side, and Feedwater Nozzle Fatigue Analyses

The steam generators are designed to ASME Section III, Subsection NB (Class 1) and Subsection NC (Class 2), 1971 Edition with addenda through Summer 1973. Although the secondary side is Class 2, all pressure retaining parts of the steam generator satisfy the Class 1 criteria, including the Class 2 secondary side boundaries.

Although the steam generator tubes have a Class 1 fatigue analysis, the safety determination for integrity of steam generator tubes now depends on managing aging effects by a periodic inspection program rather than on the fatigue analysis, described in Section A1.8. The code fatigue analysis of the tubes is theefore not a TLAA.

Except for the tubes, fatigue usage factors in the steam generator components do not depend on flow-induced vibration or other effects that are time-dependent at steady-state conditions, but depend only on effects of operational and upset transient events. At the current rate of accumulation of these events the design basis number of events should be sufficient for 60 years of operation. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 ensures that the fatigue usage factors based on those transients remain within the code limit of 1.0 for steam generator components with fatigue analyses for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.6 ASME Section III Class 1 Valves

WCGS Class 1 valves are designed to ASME Section III, Subsection NB, 1974 Edition and later addenda. At WCGS, Class 1 fatigue analyses are TLAAs only for Class 1 valves with inlets greater than four inches nominal.

For all valves the allowed NB-3545.3 N_A normal duty operations far exceed those expected to occur.

The calculated worst-case usage factors I_t for Class 1 pressurizer safety valves and for six inch swing check valves indicate that the designs have large margins, and therefore that the pressure boundaries would withstand fatigue effects for at least two of the original design lifetimes. The design of these valves for fatigue effects is therefore valid for the period of extended operation.

The calculated worst-case usage factors for the 12 inch Class 1 RHR suction gate valves and the 10 inch Class 1 check valves exceed 0.4. However, fatigue usage factors in these valves do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. As discussed in Section A3.2.1.7, the current rate of accumulation of these event cycles for Class 1 piping systems containing valves indicates that the 40-year design basis number of events should be sufficient for 60 years of operation, and that the calculated usage factors should not be exceeded. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 ensures that the assumed numbers of transient cycles for 12 inch Class 1 RHR suction gate valves and the 10 inch Class 1 check valves are not exceeded, and consequently, that the fatigue analysis TLAAs based on those transients remain valid for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.7 ASME Section III Class 1 Piping and Piping Nozzles

Class 1 reactor coolant main-loop piping supplied by Westinghouse is designed to ASME Section III, Subsection NB, 1974 edition with addenda through Winter 1975. The main loop piping fatigue analysis was performed to the 1974 edition with addenda through Winter 1975. The fatigue analyses of piping outside the main loop used code addenda through summer 1979 [USAR Table 5.2-1]. These analyses have been updated from time to time to incorporate redefinitions of loads and design basis events, operating changes, power rerate, and minor modifications.

See Section A3.2.1.8 for fatigue in the pressurizer surge lines.

See Section A3.2.1.9 for the evaluation of certain noise events affecting the fatigue analyses of the primary coolant system and reactor vessel. The evaluation of these noise events found no effect on the primary coolant piping fatigue analysis.

The hot leg surge nozzle is subject to possible thermal stratification effects. Fatigue at this location is specifically monitored, including the stratification effects.

Fatigue due to high-cycle vibration has been evaluated in thermowells added at former RTD nozzles. The calculated usage factor has been validated for the period of extended operation and remains negligible.

With the exception of the hot leg surge nozzle and thermowells, fatigue usage factors in Class 1 piping and nozzles do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 ensures that fatigue usage factors based on those transients remain within the code limit of 1.0 for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.8 Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification

NRC Bulletin 88-11 requested that licensees establish and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification and required them to inform the staff of the actions taken to resolve this issue. The original surge line fatigue analysis used code addenda through summer 1979. The surge line design was re-evaluated to the 1986 code in response to the NRC Bulletin 88-11 thermal stratification concerns. This analysis was later reevaluated for effects of snubber removals. These results have been incorporated into the piping and main-loop nozzle code design reports. The current analysis includes effects of power rerate and T_{hot} reduction.

See Section A3.2.1.4 for effects on the pressurizer surge nozzle. See Section A3.2.1.7 for effects on the hot leg surge nozzle.

The maximum calculated CUF at any location in the surge lines, under the current analysis of record, including thermal stratification effects, is less than 0.1. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 monitors fatigue in the surge line and ensures that the fatigue usage factors based on those transients remain within the code limit of 1.0 for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

The re-evaluation of the surge line for NRC Bulletin 88-11 under the 1986 code did not retroactively impose Subarticle NF-3330 stress limits for high-cycle fatigue of Class 1 supports.

A3.2.1.9 Primary Coolant System Heatup Expansion Noise Events

Since 1990, abrupt audible events have been heard inside containment at WCGS toward the end of primary system heatups. They have been attributed to an abrupt release of differential expansion energy, originally believed to be at the crossover piping support saddle shims, later found to have probably also occurred between the reactor vessel support pads and shoes, under the vessel main loop nozzles.

The evaluation of effects of these events found no effect, or only nominal effects, on stress and fatigue analyses of the reactor vessel inlet and outlet nozzles, reactor coolant piping primary loop and component supports, steam generator nozzles, and primary loop leak-before-break analysis.

The heatup noise events have been evaluated and projected to remain within the 330 cycles assumed in the fatigue evaluation.

A3.2.1.10 High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor

A leak-before-break analysis (LBB) eliminated large breaks in the main reactor coolant loops. See Section A3.2.1.11. Outside the main loop breaks are selected in accordance with Regulatory Guide 1.46, Revision 0, “Protection Against Pipe Whip Inside Containment,” and Branch Technical Positions ASB 3-1 and MEB 3-1. See USAR Section 3.6.1.

The citation of MEB 3-1 means that “intermediate breaks,” “between terminal ends,” in piping with ASME Section III Class 1 fatigue analyses are identified at any location where cumulative usage factor is equal to or greater than 0.1, with the stated exception of the reactor coolant system primary loops.

A revised stress analysis of the surge line reduced all intermediate locations below 0.1, and thereby eliminated intermediate breaks in it.

Break locations that depend on usage factor, and their absence in the surge line, remain valid as long as the calculated usage factors are not exceeded. The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 ensures that the originally calculated maximum usage factors are not exceeded, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.1.11 Fatigue Crack Growth Assessment in Support of a Fracture Mechanics Analysis for the Leak-Before-Break (LBB) Elimination of Dynamic Effects of Primary Loop Piping Failures

USAR Section 3.6.1 describes a leak-before-break analysis that eliminated the large breaks in the main reactor coolant loops, which permitted omission of evaluations of their jet and pipe whip effects. This permitted omission of large jet barriers and whip restraints. The containment pressurization and equipment qualification analyses retained the large-break assumptions.

The fracture mechanics analysis depends on a saturated rather than a time-dependent crack initiation energy integral, is therefore not time-dependent, and is therefore not a TLAA. However, the final leak-before-break submittal is also supported by a fatigue crack growth assessment for a 40-year design life, which is a TLAA.

The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 is written to confirm that the maximum usage factor in the primary loop piping remains below the number assumed for the existing analysis, and therefore that the basis for the LBB analysis remains valid for the period of extended operation, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means.

A3.2.2 ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals

The WCGS reactor vessel internals were designed after the incorporation of Subsection NG into the 1974 Edition of Section III of the ASME Boiler and Pressure Vessel Code. The design meets the intent of paragraph NG-3311(c); that is, design and construction of core support structures meet Subsection NG in full, and other internals are designed and constructed to ensure that their effects on the core support structures remain within the core support structure code limits.

The current reactor vessel internals design report incorporates effects of power rerate and of hot leg temperature reduction (T_{hot}). It identifies usage factors for the specified set of design basis transient events and for 40 years of high-cycle effects.

The greater part of each calculated fatigue usage factor is due to effects of significant transients. The review and projection of transient events and usage factor accumulation to date indicates that the specified number of each transient should not be exceeded during the 60-year period of extended operation, and the WCGS fatigue management program tracks these events. Therefore, the contribution of these transient events to fatigue usage in the internals will not exceed that originally calculated without the condition being identified, and without an appropriate evaluation being performed and any necessary mitigating actions being taken.

However, some part of fatigue usage in internals is due to the high-cycle effects, and therefore depends on steady-state operating time rather than on the number of transients. High-cycle fatigue must therefore be evaluated separately in order to extend the conclusion of the supplementary design report to the end of the 60-year licensed operating period.

For locations with reported usage factors greater than 0.66, the detailed fatigue calculations were reviewed to determine the contribution of high cycle fatigue to the total usage. In these locations, the review determined that high cycle fatigue was not calculated for the component because either the vibratory stresses are very small compared to thermal transient stresses or the usage from high cycle effects was insignificant. Therefore, the reported usage is from the specified design transients and is proportional to the numbers of transients experienced but not explicitly to time of operation.

For locations with reported usage factors of less than 0.66, some part of the fatigue usage in internals may be due to the high-cycle effects, and therefore depends on steady-state operating time rather than on the number of transient events. Because these locations have reported usage of less than 0.66, multiplying the reported fatigue usage values by 1.5 to account for 60 years of operation gives fatigue usage results less than the limit of 1.0 and is therefore acceptable. Therefore, the analysis has been projected to the end of the period of extended operation.

Fatigue Analyses of Barrel-to-Former and Baffle-to-Former Bolts

Cracked baffle-to-former bolts were found in a few offshore reactors with designs and materials similar to Westinghouse units. The failures have been attributed to a combination of time-dependent effects. Fatigue in these bolts is the subject of an ASME code analysis, which is a TLAA.

The high predicted usage factor, the additional aging effects requiring mitigation, and the fact that some of these are synergistic (e.g., fatigue and the other cracking mechanisms) dictate that management of the fatigue usage factor in these bolts will be insufficient by itself, and that an aging management program must be constructed for the bolts which either adequately address all of these effects, or which will ensure their safety function despite these effects. The Wolf Creek aging management program for reactor vessel internals for the license renewal period has not been determined. See Section A1.35 for the commitment to develop this program.

A3.2.3 Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)

Concerns with possible effects of elevated temperature, reactor coolant chemistry environments, and different strain rates prompted NRC-sponsored research to assess these effects, culminating in the guidance of NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.” Although GSI 190 has been closed for plants with 40-year initial licenses, the NUREG-1800 states that "The applicant's consideration of the effects of coolant environment on component fatigue life for license renewal is an area of review," noting the staff recommendation “…that the samples in NUREG/CR-6260 should be evaluated considering environmental effects for license renewal.”

NUREG/CR-6260 Table 5-82 identifies seven sample locations for newer Westinghouse plants such as WCGS:

- Reactor Vessel Lower Head to Shell Juncture
- Reactor Vessel Primary Coolant Inlet Nozzle
- Reactor Vessel Primary Coolant Outlet Nozzle
- Surge Line Hot Leg Nozzle
- Charging Nozzles (Loop 1 and 4 nozzles are separately monitored at WCGS)
- Safety Injection Nozzles - Boron Injection tank (BIT) or High-Head Safety Injection (HHSI) Nozzles
- Residual Heat Removal Line Inlet Transition – 45-Degree Accumulator Safety Injection (ACCSI) and RHR Cold Leg Injection Nozzles.

WCGS performed plant-specific calculations for these seven sample locations using the appropriate F_{en} factors from NUREG/CR-6583 for carbon and low-alloy steels and from NUREG/CR-5704 for stainless steels, as appropriate for the material at each location. The material-specific worst-case F_{EN} multiplier was calculated for each location, and applied to the fatigue usage factor expected at 60 Years at that location. Strain rate information was not used to determine F_{EN}.

All of these locations except the first, the vessel lower head to shell juncture, are included in the Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1. The first location is not monitored because the low projected usage factor, when multiplied by the applicable F_{EN}, remains negligible. At the first location, the expected 60-year fatigue usage factor was determined by multiplying the calculated design basis 40-year usage factor times 1.5. All others were projected from the historical and current rates of accumulation of transient cycles and usage factors. When these projected 60-year usage factors are multiplied by the respective F_{EN}, the results are all less than the code limit of 1.0. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 is structured to continue to confirm that this is so, or to initiate appropriate evaluations and corrective measures.

A3.2.4 Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in B31.1 and ASME Section III Class 2 and 3 Piping

None of ANSI B31.1 or ASME Section III Subsections NC and ND invokes fatigue analyses. However, if the number of full-range thermal cycles is expected to exceed 7,000, these codes require the application of a stress range reduction factor to the allowable stress range for expansion stresses (secondary stresses). The allowable secondary stress range is 1.0 S_A for 7000 equivalent full-temperature thermal cycles or less and is reduced in steps to 0.5 S_A for greater than 100,000 cycles. Partial cycles are counted proportional to their temperature range.

A review of ASME Section III Class 2 and 3 and B31.1 piping specifications found no indication of a number of expected lifetime full-range or equivalent full-range thermal cycles greater than 7,000 during the original 40-year plant life.

The survey of all plant piping systems found that some of the reactor coolant sample lines may be subject to more than 7,000 but less than 11,000 full temperature cycles in 60 years requiring a stress range reduction factor (SRRF) of 0.9 times the allowable stress. The WCGS design analyses of secondary stress ranges are within the limits imposed by the 0.9 SRRF in all line segments.

A3.2.5 Fatigue Design of Spent Fuel Pool Liner and Racks for Seismic Events

The WCGS spent fuel pool racks were replaced in order to accommodate a larger inventory. The design of the replacement racks included a fatigue analysis of the racks and of high-stress locations in the pool liner. These analyses are described in USAR Section 9.1A.4.3.5.4.

The analyses remain valid for any period for which the number of operating basis earthquake events (OBE) has not been and is not expected to be exceeded, assuming an additional safe shutdown earthquake (SSE) might occur. Since the remaining plant life from the present to the end of the period of extended operation (2006 to 2045) is less than that of the original license to which the numbers of OBE and SSE events apply, and since no SSE or significant OBE has occurred, these analyses remain valid for the period of extended operation.

A3.2.6 Fatigue Design and Analysis of Class IE Electrical Raceway Support Angle Fittings for Seismic Events

The design of Class IE electrical raceway included a fatigue evaluation of the effects of operating basis and safe shutdown earthquake loads (OBE and SSE loads) on angle fittings used at the connections of strut hangers to overhead supports, or at interhanger locations.

This analysis was extremely conservative, assuming 1000 allowable cycles for a deflection considerably less than the endurance limit. No seismic events have induced significant cyclic loads on these components in the 20-year operating history of the plant to date, so that the design basis number of events remains sufficient for the remainder of the original licensed operating period, plus the period of extended operation.

A3.3 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL COMPONENTS

Aging evaluations that qualify electrical and I&C components required to meet the requirements of 10 CFR 50.49 are evaluated to demonstrate qualification for the 40 year plant life are TLAAs. The existing WCGS Environmental Qualification program adequately manages component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

Continuing the existing 10 CFR 50.49 EQ program ensures that the aging effects are managed and that the EQ components continue to perform their intended functions for the period of extended operation. The Environmental Qualification of Electrical Components program is described in Section A2.2.

A3.4 CONCRETE CONTAINMENT TENDON PRESTRESS

The WCGS containment is a prestressed concrete, hemispherical-dome-on-a-cylinder structure, with a steel membrane liner. Post-tensioned tendons compress the concrete and permit the structure to withstand design basis accident internal pressures. The reinforced concrete basemat is conventionally reinforced.

To ensure the integrity of the containment pressure boundary under design basis accident loads, design predictions of loss of prestress demonstrate that prestress should remain adequate for the design life. An inspection program confirms that the tendon prestress remains within design limits throughout the life of the plant [USAR Section 3.8.1, Technical Specification Surveillance Requirement SR 3.6.1.2].

Continuing the existing ASME Subsection IWL tendon surveillance program ensures that loss of prestress aging effects will be managed and that the containment tendons will continue to perform their intended functions for the period of extended operation. The program is described in Section A2.3.

A3.5 CONTAINMENT LINER PLATE, POLAR CRANE BRACKET, AND PENETRATION LOAD CYCLES

Design of the polar crane for a finite number of loads is a TLAA at WCGS (Section A3.6.1). At some plants, though not at WCGS, the supporting crane rail brackets or other supporting structural elements may also have been designed for these cyclic loads. NUREG-1800 Section 4.6.1 notes that in some designs "Fatigue of the liner plates or metal containments may be considered in the design based on an assumed number of loading cycles for the current operating term."

At WCGS however, the only metallic components of the containment pressure boundary that are designed for a specific number of load cycles in a design lifetime are the main steam penetrations. The containment liner and the remaining penetrations were designed to stress limit criteria, independent of the number of load cycles, and with no fatigue analyses.

A3.5.1 Design Cycles for the Main Steam Line Penetrations

The BC-TOP-1, "Containment Building Liner Plate Design Report," Part II Section 1.1, describes the main steam penetration design for cyclic loads. The design basis includes

- 100 lifetime steady state operating thermal gradient plus normal operating cyclic loads ("Loading Condition V"), and
- 10 steady state operating thermal gradient plus steam pipe rupture cyclic loads ("Loading Condition IV").

The operating history to date indicates that the original design basis 100 operating cycles assumed for main steam penetrations will be adequate for the 60-year extended operating period. For license renewal, an evaluation of an equivalent ASME Section III Class 1 fatigue usage factor found that the penetrations could withstand as many as 2500 lifetime full-range thermal cycles ("Condition V" events), plus the fatigue effects of an end-of-life main steam rupture inside containment (a "Condition IV" event), with a cumulative usage factor of less than 1.0.

There is therefore more than sufficient margin in the design for any possible increase in operating cycles above the original estimate. The design of the main steam penetrations is therefore valid for the period of extended operation.

A3.6 PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

A3.6.1 Containment Polar Crane, Fuel Building Cask Handling Crane, Spent Fuel Pool Bridge Crane, and Fuel Handling Machine CMAA-70 Load Cycle Limits

The USAR Section 9.1.4 describes design of these lifting machines to Crane Manufacturers Association of America Specification No. 70 (CMAA-70 (1975)). The CMAA-70 crane service classification ("class" or "design class") for each machine depends, in part, on the assumption that the number of stress cycles at or near the maximum allowable stress will not exceed the number assumed for that design class. In operation, this means the number of significant lifts, i.e. those which approach or equal the design load, should not exceed the number of stress cycles assumed for that design class.

In all cases the design standard number of full-capacity lifts far exceeds the number expected of the machine for a 60-year period of extended operation. The lifting machine designs therefore remain valid for the period of extended operation.

A3.7 TLAAS SUPPORTING 10 CFR 50.12 EXEMPTIONS

One 10 CFR 50.12 exemption, for use of a leak-before-break analysis for the primary coolant loops, is based in part on a time-limited aging analysis of fatigue effects. See Section A3.2.1.11.