Appendix B

RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

TABLE OF CONTENTS

Appendix B

RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

LIST OF TABLES

Appendix B

RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

LIST OF FIGURES

I.A.1.2 Shift Supervisor Responsibilities

Position (NUREG-0578, 2.2.1.A)

a. 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 safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

b. 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:

   1. The responsibility and authority of the shift supervisor 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 when on duty in the control room. The idea 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.

   2. 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.

   3. 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.

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

d. 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.

Clarification

The table attached provides clarification to the above position.

Columbia Generating Station Position

The administrative duties of the shift manager have been reviewed; inappropriate functions were delegated to other personnel including the shift support supervisor. The shift support supervisor will assist the shift manager by directing personnel assigned to perform balance-of-plant operating functions and by performing shift administrative duties.

Procedures have been reviewed to ensure that the shift manager, control room supervisor, shift support supervisor, and operator functions are defined adequately to establish the shift manager as the commanding authority for plant operations relative to other plant management. The shift manager is to ensure the safe operation of the plant under all conditions. During an emergency, the responsibility for directing and controlling the actions of the operating crew to place and maintain the plant in a safe condition rests with the shift manager. During accident conditions, the shift manager will normally be in the control room at all times until properly relieved. He may elect to direct recovery activities at the scene of the accident.

This principle has been reinforced by management directive that emphasizes that the shift manager's primary responsibility is the safe operation of the plant under all conditions.

The shift manager's administrative duties will be reviewed annually by the crew operations manager to ensure that administrative responsibilities do not interfere with the primary responsibility.

Appropriate documentation will be available onsite for review by the Nuclear Regulatory Commission (NRC) I&E Branch.

This position has been accepted in the NRC Staff Safety Evaluation Report NUREG-0892 dated March 1982, section 13.5.1.8.

Table I.A.1.2-1

Shift Supervisor Responsibilities (2.2.1.A)

NUREG-0578 Position (Position Number)	Clarification
Highest Level of Corporate Management (1.)	Vice President, Nuclear Generation
Periodically Reissue (1.)	Annual Reinforcement of Company Policy
Management Direction (1.)	Formal Documentation of Shift Personnel, All Plant Management, Copy to IE Region
Properly Defined (2.0)	Defined in Writing in a Plant Procedure
Until Properly Relieved (2.B)	Formal Transfer of Authority, Valid SRO License, Recorded in Plant Log
Temporarily Absent (2.C)	Any Absence
Control Room Defined (2.C)	Includes Shift Manager Office Adjacent to the Control Room
Designated (2.C)	In Administrative Procedures
Clearly Specified	Defined in Administrative Procedures
SRO Training	Specified in ANS 3.1 (Draft) Section 5.2.1.8
Administrative Duties (4.)	Not Affecting Plant Safety
Administrative Duties Reviewed (4.)	On Same Interval as Reinforcement: i.e., Annual by Vice President, Nuclear Generation

This requirement was met before fuel loading. See NUREG-0578, Section 22.1a, Item 4 and NRC letters of September 27 and November 9, 1979

The italicized information is historical and was provided to support the application for an operating license.

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

Position *(NUREG-0737)*

In the 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 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, 39, 41, 47, 55, 57).

Changes to Previous Requirements and Guidance:

a. Modification to Clarification

1. Addresses owners' group and vendor submittals.

2. References to task action plan Items I.C.8 and I.C.9.

3. Scope of procedures review is explained.

4. Establishes configuration control of guidelines for emergency procedures.

b. Modification to Implementation

1. Deleted reference to NUREG-0578, Recommendation 2.1.9 for Item I.C.1(a)2, inadequate core cooling.

The complete NRC position description and clarification is contained in NUREG-0737 - Task I.C.1.

This requirement is to be completed by fuel load.

Clarification

None.

Columbia Generating Station Position

Columbia Generating Station (CGS) has participated, and continues to participate, in the BWR Owner's Group program to develop Emergency Procedure Guidelines for General Electric Boiling Water Reactor. Following are a brief description of the submittals to date, and a justification of their adequacy to support guidelines development.

a. *Description of Submittals*

1. *NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August 1979; including additional sections submitted in prepublication form since August 1979.*

(a) *Section 3.1.1 (Small Break LOCA).*

Description and analysis of small break loss-of-coolant events, considering a range of break sizes, location, and conditions, including equipment failures and operator errors; description and justification of analysis methods.

(b) *Section 3.2.1 (Loss of Feedwater) - revised and resubmitted in prepublication from March 31, 1980.*

Description and analysis of loss of feedwater events, including cases involving stuck-open relief valves, and including equipment failures and operator errors; description and justification of analysis methods.

(c) *Section 3.2.2 (Other Operational Transients) - submitted in prepublication form March 31, 1980; revised and resubmitted in prepublication form August 22, 1980.*

Description and analysis of each FSAR Chapter 15 event resulting in a reactor system transient; demonstration of applicability of *analyses of 3.1.1, 3.2.1, and 3.5.2.1 to each event; demonstration of applicability of Emergency Procedure Guidelines to each event.*

(d) *Section 3.3 (BWR Natural and Forced Circulation).*

Description of natural and forced circulation cooling; factors influencing natural circulation, including noncondensables; re-establishment of forced circulation under transient and accident conditions.

(e) *Section 3.5.2.1 (Analyses to Demonstrate Adequate Core Cooling) - submitted in prepublication form November 30, 1979; revised and resubmitted in prepublication form September 16, 1980.*

Description and analysis of loss-of-coolant events, loss of feedwater events, and stuck-open relief valves events, including severe multiple equipment failures and operator errors which, if not mitigated, could result in conditions of inadequate core cooling.

(f) *Section 3.5.2.3 (Diverse Methods of Detecting Adequate Core Cooling) - submitted in prepublication form December 28, 1979.*

Description of indications available to the BWR operator for the detection of adequate core cooling (detailed instrument responses are described in 3.1.1, 3.2.1, and 3.5.2.1).

(g) *Section 3.5.2.4 (Justification of Analysis Methods) - submitted in pre-publication form September 16, 1980.*

Description and justification of analysis methods for extremely degraded cases treated in 3.5.2.1.

2. *BWR Emergency Procedure Guidelines (Revision 3).*

Guidelines for BWR Emergency Procedures based on identification and response to plant symptoms; including a range of equipment failures and operator errors; including severe multiple equipment failures and operator errors which, if not mitigated, would result in conditions of inadequate core cooling; including conditions when core cooling status is uncertain or unknown.

3. NEDO-24708A, Revision 1, December 1980.

b. Adequacy of Submittals:

The submittals described in (a) above have been discussed and reviewed extensively among the BWR Owner's Group, the General Electric Company, and the NRC staff. The NRC staff has found (NUREG-0737 p. I.C.1-3) that "the analysis and guidelines submitted by General Electric Company (GE) Owners' Group…comply with the requirements (of the NUREG-0737 clarification)." In Reference 1, the Director of the Division of Licensing states, "we find the Emergency Procedure Guidelines acceptable for trial implementation (on six LRG-1 plants with applications for operating licenses pending)."

CGS believes that in view of these findings, no further detailed justification of the analysis or guidelines is necessary at this time.

Reference 1 further states, "(during the course of implementation we may identify areas that require modification or further analysis and justification." The enclosure of Reference 1 identifies several such areas. CGS will work with the BWR Owners' Group in responding to such requests.

By our commitment to work with the Owners' Group on such requests, on schedules mutually agreed to by the NRC and the Owners' Group, and by reference to the BWR Owners' Group analyses and guidelines already submitted, our response to the NUREG-0737 requirement "for reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures" is complete.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, Supplement 5 dated April 1984, section 13.5.2.2.

References

1. Letter, D. G. Eisenhut (NRC) to S. T. Rogers (BWR Owners' Group), regarding Emergency Procedure Guidelines, October 21, 1980.

I.C.2 SHIFT AND RELIEF TURNOVER PROCEDURES

Position

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

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

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

2. 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).

3. 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).

b. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by themselves 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).

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

Clarification

None.

Columbia Generating Station Position

The control room operator's checklist is designed to do the following:

a. Ensure that critical plant parameters are monitored and are within allowable limits,

b. Ensure the availability and correct alignment of essential systems, and

c. Identify all systems or components which are in a degraded mode of operation and compare each length of time in the degraded mode to Technical Specifications action requirements.

The off-going and on-coming shift manager, control room supervisor, and on-coming control room operator positions will signify checklist status and content.

A checklist designed for balance-of-plant shift turnover will identify any equipment under maintenance or test which could either (a) by itself degrade a system which is critical to the prevention and mitigation of operational transients and accidents or (b) initiate an operational transient.

The off-going or on-coming shift support supervisors and the on-coming equipment operators with rounds will signify checklist status and content for the balance-of-plant checklists.

CGS established a system to evaluate the effectiveness of the shift and relief turnover procedure.

This italicized text is historical and was provided to support the application for an operating license.

With CGS receiving an operating license December 19, 1983, and going through test and startup phases prior to that date the shift and relief turnover procedures have been under continuous scrutiny for over 2 years. This has resulted in changes reviewed and accepted by the Plant Operations Committee to increase the efficiency and effectiveness of the procedures.

I.C.4 CONTROL ROOM ACCESS

<u>Position</u> (NUREG-0578 2.2.2.A)

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 to predesignated NRC personnel. Provisions shall include the following:

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

b. 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 senior reactor operator'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 of the control room.

Clarification

None.

Columbia Generating Station Position

A Columbia Generating Station procedure has been implemented to establish the shift manager (SRO) and, in his absence, the control room supervisor (SRO) as the authority and responsibility for limiting access to the control room. Nonessential personnel are excluded from the control room when their presence is hampering operations. Nonessential personnel are defined as those not required by the shift manager to assist in safe plant operation and may include anyone not normally assigned a shift control room position. If required, plant security can be used to enforce the policy.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.1.8.

Additionally, procedures establish the same line of succession for control room authority and responsibility in the event of an emergency. The procedures specifically address lines of communication and authority for management personnel not in direct command of operations and assigned responsibilities outside the control room. Instructions or orders impacting operations are reviewed by the operations manager and transmitted to the shift manager.

I.C.6 GUIDANCE ON PROCEDURES FOR VERIFYING CORRECT PERFORMANCE OF OPERATING ACTIVITIES

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to ensure 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 NRC Task Action Plan (NUREG-0660) and Recommendation 5 of NUREG-0585 propose requiring that licensees' procedures be reviewed and revised, as necessary, to ensure 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:

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

b. 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.

c. Work permits involving tagging for maintenance or surveillance testing are verified by the shift manager (or his designee) for correct implementation of control measures. Independent verification by qualified individuals is made for installation or removal of temporary modifications such as jumpers, lifted leads or bypass lines. Routine independent verification of equipment status at the location of the equipment will be performed for return-to-service activities of all important safety-related equipment having no control room status indications. These verifications will be by qualified equipment operators.

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

e. For the return-to-service of equipment important to safety, a second qualified operator should verify proper systems alignment unless functional testing can be performed without compromising plant safety, and 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.

Columbia Generating Station Position

Procedures implement an effective system for verification of operating activities important to safety. These procedures were implemented prior to fuel load. The preparation of these procedures was guided by ANS 3.2 Section 5.2.6 and the following supplemental provisions.

a. ANS 3.2 Section 5.2.6 will be applied to both maintenance and technical specification surveillances as described below.

b. The shift manager has the designated responsibility for implementing procedures for release of systems and equipment for maintenance or surveillance testing and for return-to-service. This responsibility may be delegated to a licensed SRO. The shift manager will remain informed by reviewing records and receiving turnover.

c. Clearance tagging for maintenance or surveillance testing are independently verified by the shift manager (or his designee) for correct implementation of control measures. Independent verification is also made for installation or removal of temporary modifications such as jumpers, lifted leads, or bypass lines on safety-related or fire protection systems not controlled by approved procedures. Routine independent verification of equipment status at the location of the equipment will be performed for return-to-service activities of all safety-related and fire protection equipment having no control room status indications.

d. Equipment control procedures are implemented through the control room such that control room personnel are aware of changes being made in equipment status and the effects of such changes.

e. Routine independent verification of status at the location of safety-related or fire protection equipment is limited to return-to-service activities performed prior to startups following refueling or long-term outages in accordance with the ALARA concept to limit accumulation of personnel radiation exposures. In addition to the above, independent verification of the return-to-service position of safety-related locked valves will be made whenever their status is changed.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated March 1982, section 13.5.1.8.

I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

Position

Obtain nuclear steam supply system (NSSS) vendor review of low power testing procedures to further verify their adequacy.

This requirement must be met before fuel loading (NUREG-0694).

Clarification

None.

Columbia Generating Station Position

The NSSS vendor (General Electric Company) has reviewed and documented the low power testing procedures, power ascension test procedures, and emergency procedures. This review considered the BWR Emergency Procedure guidelines submitted to the NRC on behalf of BWR Owners' Group on June 30, 1980, by letter from R. H. Buchholz to D. G. Eisenhut.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated March 1982, section 13.5.2.3 and confirmed in I&E Inspection 84-04.

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

Position

Correct emergency procedures, as necessary, based on NRC 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, stream line break, or steam-generated tube rupture).

This action will be completed prior to issuance of a full-power license (NUREG-0694).

Clarification

None.

Columbia Generating Station Position

CGS has developed procedures based on the BWR Owners' Group Emergency Procedure Guidelines. These procedures are further addressed in response to I.C.1, Short-Term Accident Analysis and Procedure Revision.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.2.3.

I.D.1 CONTROL ROOM DESIGN REVIEWS

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 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 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 (NUREG-0737).

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 modification implemented.

Applicants for operating licenses who will be unable to complete the detailed control room design review prior to 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 the 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:

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

b. *The groupings of displays and the layout of panels,*

c. *Improvements in the safety monitoring and human factors enhancement of controls and control displays,*

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

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

f. *The operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems,*

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

h. *The categorization of alarms, with unique definition of safety alarms, and*

i. *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.

<u>Columbia Generating Station Position</u>

CGS has undertaken an aggressive program to complete a control room review program in accordance with this task.

The schedule and activities for the review of the CGS Control Room and submittal of an assessment report to the NRR are as follows:

a. *A preliminary assessment of CGS's Control Room based on the BWR Owners' Subgroup review program draft criteria and NRC draft document NUREG/CR-158 was submitted to NRR in January 1982.*

b. *A Detailed Control Room Design Review (DCRDR) Preliminary Report based on a review of the CGS Control Room by the BWR Owners' Group and CGS in-house Human Factors Task Force against the BWR Owners' Group Control Room Design Review Program Plan and NUREG-0700 was submitted to NRR in April 1983.*

c. *Based on NRR reviews of the preliminary DCRDR report and onsite audit, a Response to NRC Human Factors Engineering Preliminary Design Assessment Audit Report was submitted to NRR in October 1983.*

d. *A CGS Control Room Design Review Program Plan documenting the CGS methodology and resources used, in accordance with NUREG-0700, was submitted in February 1984.*

e. *A DCRDR Final Report, per the CGS operating license was submitted to NRR on November 1, 1985, Letter GO2-85-758.*

The schedule and activities for the implementation of corrections for the CGS Control Room are as follows:

a. *All major hardware and procedural findings noted during the preliminary DCRDR report were completed prior to fuel load.*

b. *All residual findings and findings noted in the DCRDR final report are scheduled to be completed during the first refueling outage.*

The NRC Safety Evaluation Report (SER) for the CGS DCRDR was issued as Reference 1. Energy Northwest responded to the SER in Reference 2. By Reference 3 Energy Northwest stated that all DCRDR items had been implemented. In Reference 4 the NRC stated that based upon the Reference 3 submittal, they found that CGS satisfies all of the DCRDR requirements of Supplement 1 to NUREG-0737 and that TMI Item I.D.1.2 was considered *closed (note that NUREG O737 and its Supplement 1 do not have an Item 1.D.1.2; only I.D.1).*

References:

1. *Letter, G. W. Knighton (NRC) to G. C. Sorensen (SS), "Detailed Control Room Design Review (TAC No. 56181)," dated October 13, 1987.*

2. *Letter, G. C. Sorensen (SS) to NRC, "Nuclear Plant No. 2, Detailed Control Room Design Review (TAC No. 56181)," GO2-88-074, dated March 29, 1988.*

3. *Letter, G. C. Sorensen (SS) to NRC, "Nuclear Plant No. 2, Operating License NPF-21 Detailed Control Room Design Review (TAC No. 56181)," GO2-91-198, dated October 29, 1991.*

4. *Letter, P. L. Eng (NRC) to G. C. Sorensen (SS), "Status of TMI Item I.D.1.1, 'Detailed Control Room Design Review' (DCRDR) at Washington Public Power Supply System Nuclear Project No. 2 (WNP-2) (TAC NO. 56181)," dated November 13, 1991.*

I.G.1 PREOPERATIONAL AND LOW-POWER TESTING

Position (NUREG-0660)

The objective is to increase the capability of the shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and off-normal events is conducted. Near-term operating license facilities will be required to develop and implement intensified training exercises during the low-power testing programs. This may involve the repetition of startup tests on different shifts for training purposes. Based on experience from the near-term operating license facilities, requirements may be applied to other new facilities or incorporated into the plant drill requirement (Item I.A.2.5). Review comprehensiveness of test programs.

NRR will require new operating licensees to conduct a set of low-power tests to accomplish the requirements. The set of tests will be determined on a case-by-case basis for the first few plants. Then NRR will develop acceptance criteria for low-power test programs to provide "hands on" training for plant evaluation and off-normal events for each operating shift. It is not expected that all tests will be required to be conducted by each operating shift. Observation by one shift of training of another shift may be acceptable.

NRR will develop criteria in conjunction with initial near-term operating license reviews.

Licensees will (1) define training plan prior to loading fuel, and (2) conduct training prior to full-power operation.

Clarification

None.

Columbia Generating Station Position

Energy Northwest committed to meet the intent of NUREG-0660 by performance of a special low power test subprogram which provided supplemental operator training in the areas of response to abnormal plant conditions and familiarity with critical systems. The special subprogram amplified the well-established training value of the Startup Test Program (STP) through (1) instruction on the content, goals, and requirements of the program, (2) addition of selected special tests to the STP to demonstrate abnormal scenarios and uses of critical systems and/or emergency operating procedures to control them, and (3) utilization of the knowledge and experience gained during the STP in the training programs for future operators.

The overall Startup Test Program is outlined in Chapter 14 while the conduct of operations is discussed in Chapter 13. During the preoperational and power ascension test phases, the operations personnel were intimately involved in the performance of the various test procedures. With the impetus provided by the responsible test phase organization, the operations staff was charged with establishing the required plant/system conditions, initiating and controlling the desired test transient and returning the plant/system to its normal condition. The operations staff provided the physical ability to accomplish the Startup Test Program. In this fashion, the completion of the Startup Test Program provided an unparalleled training opportunity for the operators.

The following outlines those additional actions Energy Northwest implemented to augment the extensive training benefits inherent in the existing STP program:

I. Development and Implementation of a Training Course on the STP

A. General Classroom Instruction (prior to testing)

1. STP Overview

a. Organization, Delineation of Responsibilities, Goals

b. Administrative and Emergency Procedures

c. Preop and Power Ascension Test Schedule

2. Review Selected STP Specifics, for example;

a. Pertinent Preop Test Purposes, Procedures, Anticipated Results

b. Integrated System Cold Functional Tests

c. Fuel Loading, Heatup, Power Ascension Test Purposes, Procedures, Anticipated Results

d. Special Test Subprogram Test Purposes, Procedures, Anticipated Results

3. Review Expected Utilization of STP Data

a. Documentation of Plant Safety

b. Feedback/Confirmation of Anticipated Results

B. Test Phase Instruction Performed by Test Director on a Shift Basis (during testing)

1. Review of the Immediate Test Schedule

2. Discussion of the Impending Tests: Procedures, Anticipated Results, Precautions

3. Review/Disseminate Plant Response Data from Previous Shift(s)

C. Post-STP Completion Instruction Performed by Test director (following testing)

1. Review Plant Design Changes/System Modifications Required

II. Development and Performance of a Special Test Subprogram

A. Additional RCIC System Tests

1. RCIC Operation Following Loss of AC Power to the System

2. RCIC Operation to Prove DC Separation

B. Integrated Reactor Vessel Level Instrumentation Functional Test

C. Integrated Containment Pressure Instrumentation Functional Test

D. Simulated Loss of Control and Instrument Air Test

E. Repetition of Some Normal STP Tests, for example:

1. Feedwater Pump Trip/Recirc Runback Demonstration

2. Turbine Trip/Generator Load Rejection Within Bypass Valve Capacity

3. Pressure Regulator Setpoint Changes

4. Recirculation Pump Trips

5. Feedwater Level Setpoint Changes

III. Utilization of the STP Data

A. Refine the CGS Simulator Response Models, as appropriate

B. Incorporate a Major Plant Transient Response Section in Operator Training Program, as appropriate

C. Update License Program Training and Requalification Material, as appropriate.

It was anticipated that every participating member of the operations staff would obtain valuable knowledge and experience through participation in the CGS Startup Test Program. Each received appropriate classroom instruction and through judicious scheduling of tests, most were exposed to a variety of plant/system transient responses (or review of results thereof). The training received is continually reinforced through normal requalification program refinements. Future license candidates also benefit from the training material upgrades resulting from the STP experience.

With this program outline, Energy Northwest met the intent of NUREG-0660, Item I.G.1. Specific details of the training program, additional test procedures, and documentation methods have been developed and are available for onsite NRC I&E review.

This position has been accepted in the NRC Safety Evaluation Report (NUREG-0892, dated December 1982, section 14.)

II.B.1 REACTOR COOLANT SYSTEM VENTS

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 noncondensable 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 events shall conform to the requirements of Appendix A to 10 CFR 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:

a. Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCAs 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.

b. 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 noncondensable gas which could interfere with core cooling.

2. Procedures addressing the use of the RCS 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 10 CFR 50.44 or 10 CFR 50.46.

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 noncondensable 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 RCS 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 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 RCS vent will be part of the RCS 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 10 CFR 50.46.

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 part of the design. Testing should be performed in accordance with subsection IWV of Section XI of the ASME Code for Category B valves.

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, and

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

b. BWR Design Considerations

1. Since the BWR Owners' Group has suggested that the present BWR designs have an inherent capability to vent, a question relating to the capability of existing systems arises. The ability of these systems to vent the RCS of noncondensable gas generated during an accident must be demonstrated. Because of differences among the head vent systems for BWRs, each licensee or applicant should address the specific design features of this plant and compare them with the generic venting capability proposed by the BWR Owners' Group. In addition, the ability

of these systems to meet the same requirements as the PWR vent system must be documented.

2. In addition to RCS venting, each BWR licensee should address the ability to vent other systems, such as the isolation condenser which may be required to maintain adequate core cooling. If the production of a large amount of noncondensable gas would cause the loss of function of such a system, remote venting of that system is required. The qualifications of such a venting system should be the same as that required for PWR venting systems.

c. PWR Vent Design Considerations

1. Each PWR licensee should provide a capability to vent the reactor vessel head. The reactor vessel head vent should be capable of venting noncondensable 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 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.

Columbia Generating Station Position

The reactor coolant vent line is located at the very top of the reactor vessel as shown in Figure 3.6-51. This 2-in. line contains two safety-related Class 1E motor-operated valves (MS-V-1 and MS-V-2) that are operated from the control room. The location of this line permits it to vent the entire RCS normally connected to the reactor pressure vessel (RPV), with the exception of the reactor coolant isolation cooling (RCIC) head spray piping which comprises approximately 0.6 ft^3 of volume above the elevation of the RPV. This small volume was considered in the original design of the RCIC system and is of no consequence to its operation. In addition, since this vent line is part of the original design for the unit, it has already been considered in all the design basis accident analyses contained elsewhere in the FSAR.

The Columbia Generating Station (CGS) BWR/5 is provided with 18 power-operated safety grade relief valves which can be manually operated from the control room to vent the RPV. The point of connection to the vent lines (main steam lines) from near the top of the vessel to these valves is such that accumulation of gases above that point in the vessel will not affect natural circulation of the reactor core.

These power-operated relief valves satisfy the intent of the NRC position. Information regarding the design, qualification, power source, etc., of these valves is provided in Section 5.2.2.

The BWR Owners' Group position is that the requirement of single failure criteria for prevention of inadvertent actuation of these valves, and the requirement that power be removed during normal operation, are not applicable to BWRs. These valves serve an important function in mitigating the effects of transients and at CGS provide ASME code overpressure protection. Therefore, the addition of a second "block" valve to the vent lines would result in a less safe design and a violation of the code. Moreover, the inadvertent opening of a relief valve in a BWR is a design basis event and is a controllable transient.

In addition to these power-operated relief valves, the CGS BWR/5 includes various other means of high-point venting. Among these are

a. Normally closed reactor vessel head vent valves, operable from the control room, which discharge to the drywell;

b. Normally open reactor head vent line, which discharges to a main steam line;

c. Main steam-driven RCIC system turbines, operable from the control room, which exhaust to the suppression pool; and

d. Main steam-driven reactor feedwater pumps operable from the control room, which exhaust to the plant condenser when not isolated. Condenser gases are continuously processed through the offgas system.

Although the power-operated relief valves fully satisfy the intent of the venting requirement, these other means also provide protection against the accumulation of noncondensables in the RPV.

Under most circumstances, no selection of vent path is necessary because the relief valves [as part of the automatic depressurization system (ADS)], high-pressure core spray (HPCS), and RCIC will function automatically in their designed modes to ensure adequate core cooling and provide continuous venting to the suppression pool.

Analyses of inventory-threatening events with very severe degradations of system performance have been conducted. These were submitted by GE for the BWR Owners' Group to the NRC Bulletins and Orders Task Force on November 30, 1979. The fundamental conclusion of these studies was that if only one ECCS is injecting into the reactor, adequate core cooling would be provided and the production of large quantities of hydrogen would be avoided. Therefore, it is not desirable to interfere with ECCS functions to prevent venting.

The small-break accident (SBA) guidelines emphasize the use of HPCS/RCIC as a first line of defense for inventory-threatening events which do not quickly depressurize the reactor. If these systems succeed in maintaining inventory, it is desirable to leave them in operation until the decision to proceed to cold shutdown is made. Thus the reactor will be vented via RCIC turbine steam being discharged to the suppression pool. Termination of this mode of venting could also terminate inventory makeup if the HPCS had failed also. This would necessitate reactor depressurization via the safety/relief valve (SRV), which of course is another means of venting.

If the HPCS/RCIC are unable to maintain inventory, the SBA guidelines call for use of ADS or manual SRV actuation to depressurize the reactor so that the low-pressure coolant injection (LPCI) and/or low-pressure core spray (LPCS) systems can inject water. Thus, the reactor would be vented via the SRV to the suppression pool. Termination of this mode of venting is not recommended. It is preferable to remain unpressurized; however, if inventory makeup requires HPCS or RCIC restart, that can be accomplished manually by the operator. It is more desirable to establish and maintain core cooling than to avoid venting. If the HPCS/RCIC and SRVs are not operable (a very degraded and extremely unlikely case), another emergency means of venting the reactor must be used. It is emphasized, however, that such emergency venting would be in the interest of core cooling and, therefore, could be employed under Emergency Procedure Guidelines.

It is thus concluded that there is no reason to interfere with ECCS operation to avoid venting. It is further concluded that the Emergency Procedure Guidelines, by correctly specifying operator actions for HPCS, RCIC, and SRV operation, also correctly specify operator actions to vent the reactor.

In the event of HPCS failure and continued vessel pressurization, the effect of noncondensables in the RCIC turbine steam was evaluated for three cases:

1. Continuous evolution of noncondensables due to radiolysis,

2. Quasi-continuous evolution of noncondensables due to core heatup, and

3. The presence of a quantity of noncondensables in the reactor at the time of HPCS/RCIC startup.

Case 1 is a normal operating mode for RCIC and is of no concern.

For Case 2 to exist, the core must be uncovered. Such a condition requires multiple failures as shown in the degraded cooling analyses. Core uncovery is prevented (or cladding heatup into the rapid oxidation range is prevented) when only one ECCS is operating. For small pipe break or a loss of feedwater, which would allow the reactor to remain at pressure, the HPCS and/or RCIC pumps would maintain inventory and there would be no substantial hydrogen production. If neither HPCS nor RCIC could maintain inventory, the reactor would be automatically or manually depressurized via SRVs (or via the break, for larger breaks). Low-pressure water injection systems (LPCI or LPCS) would then make up inventory. With the core covered neither the rapid generation of noncondensables nor their accumulation would be possible.

The performance of RCIC under Case 3 is of concern only if there has been a very substantial production of hydrogen due to core uncovery and there is a need to start the RCIC. This is extremely unlikely and an intolerable circumstance, because it could arise only if the core were allowed to remain uncovered for a long period with the reactor at high pressure. Automatic depressurization system operation and explicit operating instructions and the Emergency Operator Guidelines are intended to preclude this. If the level has fallen with the reactor at high pressure, the vessel would be depressurized either automatically or manually to permit low pressure injection independent of RCIC performance.

In the post-LOCA condition, it is possible to have noncondensable gases come out of solution while operating the residual heat removal (RHR) system. These gases would accumulate at the top of the RHR heat exchanger since this is a system high point and an area of relatively low flow. Gases trapped here will be vented through a 2-in. vent line with two safety-related Class 1E motor-operated valves (MO-F073A and MO-F074A or MO-F073B and MO-F074B) operated from the control room (as shown in Figure 5.4-15). As this vent line and associated valves are part of the original design, they have also been considered in the design basis accident analysis contained elsewhere in the FSAR.

The result of a break in the SRV discharge piping, or any of the other pipe lines for the systems enumerated above, would be the same as a small steam line break. A complete steam line break is part of the design basis, and smaller size breaks have been shown to be of lesser severity. A number of reactor system blowdowns due to stuck-open relief valves (also equivalent to a small steam line break) have confirmed this in practice. Thus no new analyses are required to show conformance with 10 CFR 50.46.

Because the relief valves and RCIC will vent the reactor continuously, and because containment hydrogen calculations in normal safety analysis calculations assume continuous venting, no special analyses are required to demonstrate "that the direct venting of noncondensable gases with perhaps high hydrogen concentrations does not result in violation of combustible gas concentration limits in containment."

Conclusion and Comparison with Requirements

The conclusion from this vent evaluation for CGS is as follows:

a. Reactor vessel head vent valves exist to relieve head pressure (at shutdown) to the drywell via remote operator action;

b. The reactor vessel head can be vented during operating conditions via the SRVs to the suppression pool;

c. The RCIC system provides an additional vent pathway to the suppression pool;

d. The size of the vents is not a critical issue because BWR SRVs have substantial capacity, exceeding the full power steaming rate of the nuclear boiler;

e. The SRVs vent to the containment suppression pool, where discharged steam is condensed without causing a rapid containment pressure/temperature transient;

f. The SRVs are not smaller than the NRC defined small LOCA. Inadvertent actuation is a design basis event and a demonstrated controllable transient;

g. Inadvertent actuation is of course undesirable, but since the SRVs serve an important protective function, no steps such as removal of power during normal operation should be taken to prevent inadvertent actuation;

h. A direct indication of SRV position is provided in the control room per Table 7.5-1, item 21. Temperature sensors in the discharge lines confirm possible valve leakage;

i. Each SRV is remotely operable from the control room;

j. Each SRV is seismically and Class 1E qualified;

k. Block valves are not required, so block valve qualifications are not applicable;

l. No new 10 CFR 50.46 conformance calculations are required because the vent provisions are part of the systems in the plant's original design and are covered by the original design bases; and

m. Plant procedures govern the operator's use of the relief mode for venting reactor pressure. These procedures are available for NRC inspection at the plant.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 5.4.3.1.

II.B.3 POSTACCIDENT SAMPLING CAPABILITY

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 hr) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18.75 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 hr) 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, then 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.

a. 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 hr or less from the time a decision is made to take a sample.

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

1. 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 nonvolatile isotopes),

2. Hydrogen levels in the containment atmosphere,

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

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

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

d. 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 H_2 gas in reactor coolant samples is considered adequate. Measuring the O_2 concentration is recommended but is not mandatory.

e. The time for a chloride analysis to be performed is dependent on two factors: (1) if the plant's coolant water is seawater or brackish water, and (2) 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 hr 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.

f. 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 General Design Criterion (GDC) 19 (Appendix A, 10 CFR 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 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees.)

g. 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.)

h. 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.

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

1. Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 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 μCi/g to 10 Ci/g.

2. 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.

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

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

1. 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 postaccident 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.*

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

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

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains a description of the postaccident sampling system in Section 11.6.

Columbia Generating Station is using a General Electric postaccident sampling system capable of sampling the primary containment and reactor building atmosphere and of obtaining liquid samples from the reactor, RHR loops, and various reactor building sumps. This system is designed to obtain grab samples which may be analyzed onsite or transported to offsite facilities for more detailed analysis if necessary. The sample station is located in the radwaste building and is shielded to reduce radiation exposure rates to the operator. All remote-operated valves are controlled from this area. Lead pigs are provided for radiation protection when transporting samples either to onsite facilities or offsite. A more detailed description follows.

Gas samples will be obtained from locations in the drywell, the suppression pool atmosphere, and from the secondary containment atmosphere. The sample system is designed to operate at pressures ranging from subatmospheric to maximum design pressures of the primary and secondary containment. Heat-traced sample lines are used outside the primary containment to prevent precipitation of moisture and resultant loss of particulates and iodines in the sample lines. The gas samples may be passed through a particulate filter and silver zeolite cartridge for determination of particulate activity and iodine activity by subsequent analysis of the samples on a gamma spectrometer system. Alternatively, the sample flow bypasses the particulate/iodine sampler, is chilled to remove moisture, and a 15-ml grab sample can be taken for determination of gaseous radioactivity and for gas composition by gas chromatography. This size sample vial has been adopted for all gas samples to be consistent with present offgas sample vial counting factors.

Reactor coolant samples will be obtained from two points in the jet pump pressure instrument system when the reactor is at pressure. The jet pump pressure system has been determined to be an optimum sample point for accident conditions. The pressure taps are well protected from damage and debris. If the recirculation pumps are secured, the water level will be raised about 18 in. above normal. This provides natural circulation of the bulk coolant past the taps. Also, the pressure taps are located sufficiently low to permit sampling at a reactor water level even below the lower core support plate.

A single sample line is also connected to both loops in the RHR system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool liquid sample can be obtained from the RHR loop lined up in the suppression pool cooling mode. Samples from the five drain sumps in the reactor building are also available.

The sample system isolation valves are controlled from the local control panel. The sample system is designed for a purge flow of 1 gpm, which is sufficient to maintain turbulent flow in the sample line. Purge flow is returned to the suppression pool. The high flush flow also serves to alleviate cross-contamination of the samples when switching from one sample point to another.

All liquid samples are taken into septum bottles mounted on sampling needles. The sample station is basically a bypass loop on the sample purge line. In the normal lineup, the sample flows through a conductivity cell (readable range 0.1 to 1000 μS/cm) and then through a ball valve bored out to 0.10-ml volume. Flow through the sample panel is established, the valve is rotated 90°, and a syringe is used to flush the sample plus a measured volume of diluent (generally 10 ml) through the valve and into the sample bottle. This provides a dilution of 100:1 to the sample. Alternatively, the valve sampling sequence can be repeated 10 times to provide a 1-ml sample diluted 10:1. The sample is transported to the laboratory for further dilution and subsequent analysis. Alternatively, the sample flow can be diverted through a 70-ml bomb to obtain a large pressurized volume. This 70-ml volume can be circulated and depressurized into a known volume gas expansion chamber. The pressure change in this chamber will be used to calculate the total dissolved gases in the reactor coolant. A grab sample of these gases may be taken through a septum port for subsequent analysis. Ten milliliter aliquots of this degassed liquid can also be taken for on or offsite chemical analyses requiring a relatively large sample. A radiation monitor in the liquid sample enclosure monitors liquid flow from the sample station to provide immediate assessment of the sample activity level. This monitor also provides information as to the effectiveness of the demineralized water flushing of the sample system following sample operation. The control instrumentation is installed in two 2 ft x 2 ft x 6 ft high standard cabinet control panels. One panel contains the conductivity and radiation level readouts. Another control panel contains the flow, pressure and temperature indicators, and the various control valves and switches.

A graphic display panel, installed directly below the main control panel, shows the status of the pumps and valves at all times. The panel also indicates the relative position of the pressure gauges and other items of concern to the operator. The use of this panel will improve operator comprehension and assist in trouble-shooting operation.

Appropriate sample handling tools, a gas sampler vial positioner and gas vial cask are available to the operator at the sampling station. The gas vial is installed and removed by use of the vial positioner through the front of the gas sampler. The vial is then manually placed down in the cask with the positioner which allows the vial to be maintained about 3 ft from the individual performing the operation.

The small-volume (10 ml) liquid sample is remotely obtained through the bottom of the sample station by use of the small-volume cask and cask positioner. The cask positioner holds the cask and positions the cask directly under the liquid sampler. The sample vial is manually raised within the cask to engage the hypodermic needles. When the sample vial has been filled, the bottle is manually withdrawn into the cask. The sample vial is always contained within lead shielding during this operation. The cask is then lowered and sealed prior to transport to the laboratory.

A large-volume cask and cask positioner is available for transporting large liquid samples. A 21-ml bottle is contained within a lead shielded cask. This sample bottle is raised from its location in the cask to the sample station needles for bottle filling. The sample station will only deliver 10 ml to this sample bottle. When filled, the bottle is withdrawn into the cask. The sample bottle is always shielded by 5 to 6 in. of lead when in position under the sample station and during the fill and withdraw cycles, thus reducing operator exposure.

The cask is transported to the required position under the sample station by a dolly cask positioner. When in position this cask is hydraulically elevated approximately 1.5 in. by a small hand pump for contact with the sample station shielding under the liquid sample enclosure floor. The sample bottle is raised, held, and lowered by a simple push/pull cable. The cask is sealed by a threaded top plug that inserts above the sample bottle. The weight of this large-volume cask is approximately 700 lb.

The particulate filters and iodine cartridges are removed via a drawer arrangement. The quantity of activity which is accumulated on the cartridges is controlled by a combination of flow orificing and time sequence control of the flow valve opening. In addition, the deposition of iodine is monitored during sampling using a radiation detector installed adjacent to the cartridge. These samples will hence be limited to activity levels which will normally not require shielded sample carriers to transport the samples to the laboratory.

The power supply to the sample station and all associated equipment will not be shed during accident conditions. The system design is such that a sample can be drawn and analyzed within the required 3 hr, after a 1 hr preparation time.

The postaccident sampling station will provide conductivity measurements in line as an indicator of liquid chemical concentrations and changing chemical conditions. The system allows collection of grab samples for gas analysis of O_2, N_2, H_2, and direct gamma spectrometric determination of aliquots of gas samples. The system also allows collection of iodine samples on a silver zeolite cartridge to minimize noble gas interference in the determination of iodine isotopic content. Liquid samples will be analyzed for pH using a semimicro pH electrode and additionally analyzed for boron and chloride using ion chromatography. An aliquot of the sample may also be analyzed for gross activity or isotopic content by gamma ray spectrometry. All laboratory analysis meet Regulatory Guide 1.97 requirements for sensitivity and range, with the exception of the range for dissolved gases. However, the analytical capability for dissolved gases is consistent with the maximum dissolved gas concentrations expected for BWRs.

The postaccident sample system will be used quarterly for operability testing. During this testing a reactor coolant sample will be taken and analyzed for gamma isotopic content. In addition, a containment atmosphere sample will be taken and analyzed for gas composition and gamma isotopic content. The results of these analyses will be compared, where possible, to results obtained through normal plant sampling systems to verify the representatives of postaccident system samples. Classroom and practical factors training will be provided on system operation, as well as proper handling and analysis of highly radioactive samples. Refresher training will be provided annually.

A yearly drill will be performed in which the postaccident sample system will be used to obtain samples. These samples will be drawn, transported, and analyzed for accident parameters as if they were postaccident highly radioactive samples.

Based on information developed by General Electric, Energy Northwest has developed plant-specific procedures for the determination of the extent of core damage under accident conditions. The procedures provide for distinguishing between fuel cladding failure and fuel melt based on isotopes present and concentration. The extent of damage is based on concentrations present of isotopic mixture of xenon, krypton, iodine, and cesium.

The estimated maximum potential whole body dose to retrieve a reactor coolant sample under worst-case accident conditions is 0.36 rem; the source being airborne noble gas activity in the radwaste building from effluent releases. Lapsed time is about 1 hr.

The maximum dose rate from a 0.1 ml reactor coolant sample (1 hr decay) in a 4-in.-thick lead transport cask is less than 5 mR/hr at 1 ft. Exposure to analyze a sample is expected to be less than 100 mR.

All valves used are fully qualified for the environment in which they are located inside and outside reactor containment.

Power for the postaccident sampling equipment is supplied from either Division 1 or Division 2 critical power sources and will be available during accident conditions.

The staff review of this position in NUREG-0892, dated December 1982, recognized several issues requiring resolution and consolidated them in Licensing Condition 9. Subsequent Energy Northwest submittals, primarily Amendment 23 to the FSAR, resulted in the staff finding the postaccident sampling system acceptable in Supplement 4 NUREG-0892, section 9.3.2.4. A requirement to have the system completed and operable prior to exceeding 5% power was made a condition to the license (NPF-21 issued December 20, 1983). Energy Northwest letter GO2-84-272 dated April 27, 1984, reported the system completed and operable thus satisfying the licensing condition.

II.F.1.3 Containment High-Range Radiation Monitor

Position

Radiation level monitors with a maximum range of 10^8 R/hr shall be installed in containment. 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

a. Provide two radiation monitor systems in containment which are documented to meet the requirements of Table II.F.1-3.

b. The specification of 10^8 R/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 containment environments but gamma-sensitive instruments can be so qualified. 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.

c. The monitors shall be located in containment(s) in a manner as to provide a reasonable assessment of area radiation conditions inside 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.

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

e. 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 II.F.1-3. 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.

Columbia Generating Station Position

This italicized text is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in Sections 7.5.1.5.3, 7.5.2.2.3, 11.5.2.2.3.2, and Table 7.5-1, item 8.

Columbia Generating Station concurs with the intent of this position and has installed high range gamma detection monitors in the following primary containment locations:

a. 515 ft level Azimuth 290°and
b. 516 ft level Azimuth 51.5°.

The detectors are unshielded and mounted on the wall in areas least influenced by shielding due to surrounding piping, etc. They are accessible for calibration and will be calibrated according to the Technical Specifications. Plant drawings will be revised to reflect their addition and location.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated December 1982, section 12.3.4.1.

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 $\pm$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, 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.

II.F.1.4 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

a. *Design and qualification criteria are outlined in Appendix A;*

b. *Measurement and indication capability shall extend to 5 psia for subatmospheric containments;*

c. *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;*

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

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

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in the following sections: 7.5.1.5.1, 7.5.2.2.3, and Table 7.5-1, item 37.

Columbia Generating Station has designed a system to meet this criteria. A description of the system is provided in Section 7.5.

The range, accuracy, and response time of these instruments are

Range	= *-5 to +3 psig*
	0 to 25 psig
	0 to 180 psig
Instrument accuracy (loop)	= $\pm$*2% of full scale*

Response time = 0 to 100% full scale in less that 1 sec

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, sections 6.2.1.1.1 and 7.5.2.6.

II.F.1.5 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-gal capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 ft above the normal water level of the suppression pool.

Clarification

a. *The containment wide-range water level indication channels shall meet the design and qualification criteria as outlined in Appendix A. The narrow-range channel shall meet the requirements of Regulatory Guide 1.89;*

b. *The measurement capability of 600,000 gal 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;*

c. *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;*

d. *For BWR pressure-suppression containments, the 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; and*

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

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in the following sections: 7.5.1.5.7, 7.5.2.2.3, and Table 7.5-1, item 14.

In Columbia Generating Station, the variable to be measured is the suppression chamber water level. Columbia Generating Station has expanded its suppression chamber water level instruments to cover this requirement. A description is provided in Section 7.5.

The accuracy and response time of this instrument are

Instrument accuracy	*= ± of full scale*
Instrument response time	*= 0 to 100% of full scale in less than 1 sec*

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, sections 6.2.1.1.2 and 7.5.2.6.

II.F.1.6 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% hydrogen concentration under both positive and negative ambient pressure.

Clarification

a. *Design and qualification criteria are outlined in Appendix A,*

b. *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, and

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

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in the following sections: 6.2.5.2.2, 7.5.1.5.4, 7.5.2.2.3, and Table 7.5-1, item 10.

Columbia Generating Station concurs with the intent of this position. The existing monitors are redundant and provide continuous display and redundant recording in the control room. The instruments are seismically and environmentally qualified to Class 1 requirements with a range *of 0-30% hydrogen concentration. A complete design description is provided in Section 6.2.5.2.*

The accuracy of this instrument is

Instrument accuracy (loop) = $\pm 0.2\%$ *H_2 in the range 2-6 H_2 and*
$\pm 2.0\%$ *for remainder of full scale*

II.F.2 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

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 (NUREG-0737).

Clarification

None.

Columbia Generating Station Position

CGS actively participated in the efforts of the BWR Owner's Group (BWROG) and the Licensing Review Group (LRG) to develop an industry understanding of NRC's concerns and an approach to detect inadequate core cooling.

An analysis of in-core thermocouples, as proposed in recently published Safety Evaluation Reports applicable to BWRs, led the BWROG, LRG, and CGS to conclude that in-core thermocouples did not serve as effective instruments for detection of inadequate core cooling and did not substantially improve the safety of the plant. The two major deficiencies of incore thermocouples are inadequate (i.e., long) response time and potentially erroneous indications. In addition, a risk assessment of the effect on the addition of in-core thermocouples has concluded that even if in-core thermocouples were arbitrarily assumed to provide an effective backup to the plant water level detectors, overall plant risk would not be significantly reduced. Based on this risk analysis, in-core thermocouples were not considered to be a cost effective modification for CGS. The results of the above studies were presented to the NRC by the BWROG and LRG executives in a meeting in Bethesda on December 17, 1981.

In Operating License NF-21 issued December 19, 1983 the staff conditioned the license to "implement the staff's requirements regarding additional instrumentation for detection of inadequate core cooling which may result from the staff's review of the BWR Owner's Group reports (SLI 8211 and SLI 8218)…." Generic Letter 84-23 comprised the staff's review and requested additional information. The Energy Northwest response to Generic Letter 84-23, Letter GO2-84-617 dated November 27, 1984, satisfied the licensing condition and closed this issue.

II.K.1.5 <u>Assurance of Proper Engineered Safety Feature Functioning</u>

<u>Position</u>

Review all valve positions, positioning requirements, positive controls, and related test and maintenance procedures to ensure proper engineered safety feature (ESF) functioning. See NRC Bulletins 79-06A Item 8, 79-06B Item 7, and 79-08 Item 6.

This requirement shall be met before fuel loading.

<u>Clarification</u>

None.

<u>Columbia Generating Station Position</u>

This italicized information is historical and was provided to support the application for an operating license. The FSAR discusses this topic in Sections 7.1.2.4, 7.3.1.1, 7.3.2.1.2, 7.3.2.1.3, and Appendix B, Section I.C.6.

Directives on valve positioning requirements, positive controls, and test and maintenance procedures associated with ESF systems have been prepared. Motor-operated valves in safety systems are normally maintained in a configuration such as to require the least number of valve automatic movements on system actuation. System initiation logic is such that valves automatically move to the required position when required. The position of vital manual ECCS valves is controlled by the use of and documentation of locks on valve handwheels. In addition, numerous vital manual valves have position status indicating lights in the control room.

Columbia Generating Station is equipped with ESF system status displays, which continuously monitor the ESF systems and provide indication to the operator of a system bypass or inoperability introduced during testing or maintenance which renders the system(s) unable to respond to an initiation signal. Typical parameters monitored include the following:

a. Valve position,

b. Power available to motor-operated valves,
c. Initiation logic power available,
d. Power sources (including emergency diesels) available, and
e. Breaker status.

Alarms are provided on a system level basis. Indication is provided on a component level basis.

Surveillance and testing procedures for ESF systems will include checks to ensure the system is returned to standby status on completion of testing.

When ESF equipment is removed from service for maintenance, procedures require documentation of removal and return to service. Functional tests of equipment returned to service following maintenance are required by these procedures to ensure operability. NUREG-0892, the WNP-2 Safety Evaluation Report, discussed this issue and listed confirmation of procedures as confirmatory issue No. 22. Energy Northwest letter GO2-83-247 dated March 23, 1983, "Confirmatory Issue No. 22, Assurance of ESF Functioning (II.K.1.5) and Safety-Related System Operability Status (II.K.1.10)," satisfied the confirmatory issue, subsequently listed as resolved in Supplement 4 to NUREG-0892.

II.K.1.22 Proper Functioning of Heat Removal Systems

Position

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense. (IE Bulletin 79-08).

Clarification

None.

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains information regarding RCIC operation in Sections 5.4.6 and 7.4.1.1; information regarding HPCS is contained in 6.3.2.2.1 and 7.3.1.1.1.1. RHR information is contained in Sections 5.4.7.1.1, 6.2.2 and 7.3.1.1.5 (suppression pool cooling mode) and 5.4.7.1.5 and 5.4.7.2.6 (shutdown cooling mode).

Energy Northwest letter GO2-80-107, dated May 23, 1980, responded to IE Bulletin 79-08. Additional information pertaining to the above requirement is provided below.

Initial Core Cooling:

Following a loss of feedwater and reactor scram, a low reactor water level signal (level 2) will automatically initiate main steam line isolation valve closure. At the same time this signal will put the HPCS and RCIC systems into the reactor coolant makeup injection mode. These systems will continue to inject water into the vessel until a high water level signal (level 8) automatically trips RCIC and closes the HPCS injection valve. The HPCS pump remains running on minimum flow bypass.

Following a high reactor water level 8 trip, the HPCS injection valve will automatically reopen when reactor water level decreases to low water level 2. The RCIC system will automatically reinitiate after a high water level 8 trip when reactor water level decreases to low water level trip 2.

The HPCS and RCIC systems have redundant supplies of water. Normally they take suction from the condensate storage tank (CST). The HPCS and RCIC systems suctions will automatically transfer from the CST to the suppression pool if the CST water is depleted or, for the HPCS system, the suppression pool water level increases to a high level.

The RCIC system will start automatically on receipt of a low water level (level 2) initiation signal. On receipt of this initiation signal, the following events occur simultaneously unless otherwise noted:

a. *Test bypass valves to condensate storage tank closes (if open);*

b. *Steam supply valve to turbine opens;*

c. *Pump discharge injection valve opens when the turbine steam supply valve is open;*

d. *Gland seal system starts;*

e. *Cooling water supply valve to lube oil cooler opens;*

f. *Pump suction valve from condensate storage tank opens (if closed);*

g. *The turbine control system brings the turbine up to speed as soon as the steam supply valve leaves its full closed position. Pump discharge flow develops as soon as the pump discharge pressure is sufficient to open the check valve between the pump and the reactor vessel. As pump discharge and steam inlet pressure change with a variable reactor pressure range, the control signal will be sent to the turbine to maintain constant steady state pump flow; and* *h. When pump discharge pressure reaches a predetermined pressure, the minimum flow valve opens until system flow reaches a predetermined flow, then it will close.*

RCIC flow may be directed away from the vessel by diverting the pump discharge to the CST. This is accomplished by closing injection valve RCIC-V-13 and opening the test return valves (RCIC-V-22 and 59). The system is returned to injection mode by closing RCIC-V-59 and then opening RCIC-V-13. This mode of operation will not be used during events where an unacceptable source term is identified in primary containment. Diverting RCIC flow to the CST is not a safety-related function nor does this mode affect the ability of RCIC to initiate during plant transients. The system automatically switches to injection mode if the water level decreases to the low level initiation point (Level 2).

The HPCS system will start automatically upon receipt of a low water level (level 2) initiation signal. Upon receipt of this initiation signal, the following events occur simultaneously unless otherwise noted:

a. High-pressure core spray diesel generator starts;

b. High-pressure core spray pump starts;

c. High-pressure core spray suction valve and HPCS injection valve open;

d. Condensate storage tank and suppression pool test return and bypass valves close (if open);

e. Minimum flow bypass valve automatically opens if HPCS pump is delivering pressure and system flow is low. Minimum flow bypass valve automatically closes when the flow rate from the pump reaches a predetermined flow;

f. High-pressure core spray service water pumps starts; and

g. High-pressure core spray room cooler fan starts.

The operator can manually initiate the HPCS and RCIC systems from the control room before the level 2 automatic initiation level is reached. The operator has the option of manual control after automatic initiation. The operator can verify that these systems are delivering water to the reactor vessel by

a. Verifying reactor water level increases when systems initiate,

b. Verifying systems flow using flow indicators in the control room, and

c. *Verifying system flow is to the reactor by checking control room position indication of motor-operated valves. This ensures no diversion of system flow to other than the reactor.*

Therefore, the HPCS and RCIC can maintain reactor water level at full reactor pressure and until pressure decreases to where low pressure systems such as the LPCS of LPCI can maintain water level.

Containment Cooling:

After reactor scram and isolation and establishment of satisfactory core cooling, the operator would start containment cooling. This mode of operation removes heat resulting from SRV discharge to the suppression pool. This would be accomplished by placing the RHR system in the containment/suppression pool cooling mode, or the suppression pool spray mode, i.e., RHR suction from and discharge to the suppression pool. A summary of the operator actions is given in the following:

a. *Start the associated RHR standby service water (SW) pump, if not already running,*

b. *Open the SW pump discharge valve, if not already open,*

c. *Open the SW loop return valve, if not already open,*

d. *Start the associated RHR pump,*

e. *Close the associated RHR heat exchanger bypass valve,*

f. *Adjust system flow by adjusting the RHR test return valve if in the suppression pool cooling mode, and*

g. *Open the suppression pool spray valve if in the spray mode.*

The Operator could verify proper operation of the RHR system containment cooling function from the control room by the following:

a. *Verifying RHR and SW system flow using system control room flow indicators,*

b. *Verifying correct RHR and SW system flow paths using control room position indication of motor-operated valves, and* *c. On branch lines that could divert flow from the required flow paths, closing the motor-operated valves and noting the effect on RHR and SW flow rate.*

Extended Core Cooling:

When the reactor has been depressurized, the RHR system can be placed in the long-term shutdown cooling mode. The operator manually terminates the containment cooling mode of one of the RHR loops and places the loop in the shutdown cooling mode as follows:

a. Trip the RHR pump to be used for shutdown cooling,

b. Close associated motor-operated valve in the suppression pool suction and LPCI discharge line to the vessel,

c. Open shutdown cooling suction valves from and discharge valves to the reactor vessel, and

d. Restart the RHR pump.

In this operating mode, the RHR system can cool the reactor to cold shutdown. Proper operation and flow paths in this mode can be verified by methods similar to those described for the containment cooling mode.

In conclusion, the plant design is fully adequate to meet the intent of the requirements of auxiliary heat removal when the main system is inoperable.

II.K.1.23 Reactor Vessel Level Instrumentation

Position

Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems (IE Bulletin 79-08).

Clarification

None.

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for the Reactor Vessel Level

Instrumentation and the design basis of the Safety Related Display Instrumentation in the following sections: 7.5.1.1.1, 7.7.1.1.2.2, 7.7.1.4.2.1, 7.5.2, and Table 7.5-1.

NEDO-24708 describes the multiple water level instrumentation provided in the BWR control room for the operator. An outline of the specific indication for Columbia Generating Station is provided in the following paragraphs, which fully meets the intent of the plant requirements and the NRC requirements.

Reactor vessel water level is continuously monitored by four recorders for normal, transient, and accident conditions. These four instruments are divided into two divisions of two instruments each to provide an overlapping range from above the maximum operating level to below the active core. Thus, adequate information is provided to the operator for manual initiation of safety actions and for assurance of the vessel water level at all times.

Those sensors used to provide automatic safety equipment initiation are arranged in a four-quadrant vessel tap configuration with the four sensors divided electrically between two divisions.

In addition, the operating procedures will reflect the requirements for the operators to also rely on the information provided by other plant parameter indications relating to vessel level.

A separate set (to that described above) of range level instrumentation provides reactor level control via the reactor feedwater system. This set also indicates or records in the control room. Additionally, an upset range (0-180 in.) and a shutdown range (0-400 in.) are provided for operator information.

The safety-related systems or functions served by safety-related reactor water level instrumentation are the following:

RCIC
HPCS
LPCS
RHR/LPCI
ADS
Nuclear steam supply shutoff system (NSSSS)
Reactor protection system (RPS)
Standby gas treatment system (SGTS)
Emergency power system
Secondary containment isolation
Main control room and critical switchgear HVAC
Standby service water system
Containment instrument air system
Trip of nonessential loads

Low reactor vessel water level is used in the initiation logic of all systems listed above. In addition, the RCIC and HPCS systems shut down on high reactor vessel water level. HPCS and RCIC will automatically restart if low reactor level is again reached (see response to TMI Items II.K.1.22 and II.K.3.13, respectively, for further discussion). Additional information about reactor vessel level instrumentation is also provided in Section 5.2 and in Figure 3.6-1.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated March 1982, section 7.5.2.1.

II.K.3.21 *Restart of Core Spray and Low Pressure Coolant Injection Systems*

Position

The core spray and low pressure coolant injection (LPCI) system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart, if required, to assure adequate core cooling. Because this design modification affects several core cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

Clarification

Modification of system design should be made in accordance with those requirements set forth in Sections 4.12, 4.13, and 4.16 of IEEE Standard 279-1971 with regard to protective function bypasses and completion of protective action once initiated.

Columbia Generating Station Position

CGS as a participant in the BWR Owner's Group endorses the position presented in the letter dated December 29, 1980, from D. B. Waters to the NRC (attention D. G. Eisenhut), Subject: "BWR Owner's Group Evaluation of NUREG-0737 Requirements." The position presented in enclosure 2 to this letter concludes that the current system design is adequate and no design changes are required. CGS concurs in this position.

It should be noted that this design allows the operator to evaluate the plant and avoid an automatic restart that may have an adverse impact on the situation.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 7.3.2.1.

II.K.3.25 Effect of Loss of Alternating-Current Power on Pump Seals

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 hr, 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 Item II.K.2.16.

Columbia Generating Station Position

Columbia Generating Station, as a participant in the BWR Owners' Group, endorses the position developed by General Electric for the Owners' Group. This position has been transmitted in a letter from the BWR Owners' Group to the NRC, T. J. Dente to Darrell G. Eisenhut, dated September 21, 1981. In this supplement to the BWR Owners' Group evaluation of NUREG-0737, Item II.K.3.25, General Electric presented test data from a test performed at the Bingham Pump Company's test facility in 1973 on the CGS recirculation pump. During the operability testing of the pump at rated temperature and pressure the seal cavity was deprived of seal purge and the external heat exchanger was deprived of coolant. As a result, the seal cavity temperature exceeded 270°F. Test personnel visually monitored pump leakage for more than five hours and observed no leakage beyond the capability of the 1-in. seal drain lines, less than 5 gpm. These test results provide confirmation that loss of cooling to the Bingham pump seal for 5 hr does not lead to unacceptable seal leakage. This loss is easily compensated for by normal water level controls and presents no hazard to the health and safety of the public.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 15.1.2.

II.K.3.44 Adequate Core Cooling for Transients with a Single Failure

Position

For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result in a stuck-open relief valve should be included in this category (NUREG-0737).

Clarification

None.

Columbia Generating Station Position

CGS as a member of the BWR Owners' Group endorses the following position statement and analysis prepared by GE on behalf of the Owners' Group:

Introduction:

This report has been prepared as the BWR Owners' Group generic response to NUREG-0737 Task Item II.K.3.44 which addresses the issue of adequate core cooling for transients with a single failure for those plants identified in Table II.K.3.44-4.

At the outset it should be noted that the conditions described in II.K.3.44 (i.e., transients plus single failures) go beyond the current BWR design basis and that the item's reference to transients with multiple failures goes beyond the regulatory requirements as specified in Regulatory Guide 1.70, Revision 3. The multiple failures specified involve consideration of a stuck-open relief valve (SORV) combined with the worst single failure. GE and the Owners' Group continues to support the current BWR design basis approach. This report is intended to provide information to address Item II.K.3.44, but does not reflect our intention to change the current BWR design basis approach.

It is shown that, for the GE BWR/2 through BWR/6 plants, the core remains covered for any transient with the worst single failure. This is achieved without any operator action to manually initiate ECCS or other inventory makeup systems. The worst transient with the worst single failure is shown to be the loss of feedwater (LOF) event with a failure of the high pressure ECCS or one isolation condenser (IC) loop, whichever is applicable.

For the bounding LOF event, studies which included even more degraded conditions have been documented in Reference 1. The degraded conditions cover the failure of HPCS (or HPCI or FWCI or IC) and one SORV. Reference 1 shows that the core will remain covered and therefore that no fuel failure would occur.

Criteria, Scope and Assumptions:

NUREG-0737 Item II.K.3.44 requires that the licensees demonstrate adequate core cooling to prevent the fuel from incurring significant damage for the anticipated transients combined with the worst single failure. To meet this requirement, either one of the following two criteria should be satisfied:

a. The reactor core remains covered with water until stable conditions are achieved, or

b. No significant fuel damage results from core uncovery.

For BWR plants, this report will show that Criterion 1 is met. The report makes the following assumptions:

a. A representative plant of each BWR product line, BWR/2 through BWR/6, is used to represent all of the plants of that product line,

b. The anticipated transients as identified in NRC Regulatory Guide 1.70, Revision 3 were considered,

c. The single failure is interpreted as an active failure, and

d. All plant systems and components are assumed to function normally, unless identified as being failed.

Discussion:

Table II.K.3.44-1 lists all of the transients which were considered in this study. The event sequence of each transient was examined for each product line to determine the impact on core cooling. The following three factors were used to determine the worst transient and the worst single failure:

a. Reduction or loss of main feedwater or coolant makeup or heat removal systems, especially high pressure systems, e.g., HPCI, feedwater coolant injection (FWCI), HPCS, RCIC or isolation condenser (IC),

b. Steam release paths causing rapid reactor coolant inventory loss, e.g., SRVs, turbine, or turbine bypass valves, and

c. Power level, especially the timing of scram.

Based on these considerations, a comparison was made among the transients in Table II.K.3.44-1.

In Reference 2, the events of Table II.K.3.44-1 are compared in detail for a typical BWR/4 plant. In particular the impact on core cooling for each transient is evaluated by comparison to the analysis results for the LOF event in the section titled "Applicability of Analyses." It is found that the LOF event is the most severe transient from the core cooling viewpoint due to its rapid depletion of reactor coolant inventory. This conclusion has generic applicability to all BWR product lines covered by this study.

The same approach was also used to select the single failures which would pose the greatest challenge to core cooling. Among all of the possible failures considered (Table II.K.3.44-2 the following failures are identified as the most important ones:

a. Failure of HPCI or HPCS or FWCI or one IC loop, whichever is applicable,
b. Failure of RCIC, and
c. One of the SRVs, which has opened as a result of the transient, fails to close.

Items a and b are the possible limiting failures because they represent loss of high pressure inventory makeup or heat removal systems which would be relied on following a loss of feedwater event. Item c is a possible limiting failure, because it results in the largest steam release rate from the vessel compared to other possible release paths (e.g., a stuck-open turbine bypass valve). No other failures identified in Table II.K.3.44-2 result in a direct challenge to core cooling capability.

Because of the relatively low steam loss capacity through one SORV (Item c) compared to the makeup water capacity of the highest capacity makeup water system, the failure of the highest capacity high pressure makeup system (Item a) would be worse than a stuck-open relief valve (Item c). For example, for a typical BWR/4, representative values of HPCI makeup and SRV flow are 18% and 6% of rated feedwater flow, respectively. Because of the higher makeup rate of HPCI/HPCS relative to RCIC (3% of rated feedwater flow), Item a would be worse than Item b. Table II.K.3.44-3 lists the worst combination of transient and single failure for the GE BWR product lines covered by this study.

Even with the worst single failure in combination with the LOF event, the RCIC or at least one IC loop will function to provide makeup and/or to remove decay heat while the vessel pressure remains high. The design basis for the RCIC or the IC is such that they are capable of removing decay heat with the vessel being isolated. Analyses of the LOF event with the worst single failure have been performed to support this conclusion. For example, for BWR/2 plants, such analyses are documented in Reference 1, Table 3.2.1.1.5-5. These analyses show that the isolation condenser heat removal capacity is greater than the decay heat generation rate and will lead to a safe and stable condition. Similar analysis have been performed for representative plants with the RCIC system. These analyses show that for the worst transient *with the worst single failure, the minimum water level for different BWR product lines ranges from 6 ft to 11 ft above the top of the active fuel.*

With even more degraded conditions, i.e., one SORV in addition to the worst case transient with the worst single failure, reference plant analyses in Reference 1, Tables 3.2.1.1.5-9 and 3.2.1.1.5-10 show that for the plants analyzed the RCIC system can automatically provide sufficient inventory to keep the core covered even with a single failure plus a SORV. This capability is not a design basis for the RCIC system, and not all plants have been analyzed to demonstrate this capability. If a plant should not have this capability, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV. It should be noted that manual depressurization is the proper operator action for all plants during loss of inventory conditions when the high pressure cooling system(s), are unable to restore and maintain RPV level. These proper operator actions are allowed for in the NUREG-0737 requirement.

For plants without RCIC, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV.

Conclusion:

The anticipated transients in NRC Regulatory Guide 1.70, Revision 3, were reviewed for all BWR product lines BWR/2 through BWR/6 from a core cooling viewpoint. The LOF event was identified to be the most limiting transient which would challenge core cooling. The BWR is designed so that the high pressure makeup or inventory maintenance systems or heat removal systems (HPCI, HPCS, FWCI, RCIC or IC) are independently capable of maintaining the water level above the top of the active fuel given a loss of feedwater. The detailed analyses show that even with the worst single failure in combination with the LOP event, the core remains covered.

Furthermore, even with more degraded conditions involving one SORV in addition to the worst transient with the worst single failure, studies show that the core remains covered during the whole course of the transient either due to RCIC operation or due to manual depressurization.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 15.1.2.

References:

1. *Section 3.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, March 31, 1980.*

2. *Section 3.2.2 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, June 30, 1980.*

3. Section 3.5.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, August 31, 1979.

Table II.K.3.44-1

Summary of Initiating Transients
(Reference: NRC Regulatory Guide 1.70, Revision 3)

1. *Loss of feedwater heating*
2. *Feedwater controller failure - maximum demand*
3. *Pressure regulator failure - open*
4. *Inadvertent safety/relief valve opening*
5. *Inadvertent residual heat removal (RHR) shutdown cooling operation*
6. *Pressure regulator failure - closed*
7. *Generator load rejection*
8. *Turbine trip*
9. *Main steam isolation valve (MSIV) closure*
10. *Loss of condenser vacuum*
11. *Loss of normal ac power*
12. *Loss of feedwater flow*
13. *Failure of RHR shutdown cooling*
14. *Recirculation pump trip*
15. *Recirculation flow control failure - decreasing flow*
16. *Rod withdrawal error*
17. *Abnormal startup of idle recirculation pump*
18. *Recirculation flow control failure - increasing flow*
19. *Fuel loading error*
20. *Inadvertent startup of high pressure core spray (HPCS) or high pressure coolant injection (HPCI) or feedwater coolant injection (FWCI) or isolation condenser (IC), whichever is applicable.*

Table II.K.3.44-2

List of Single Failures Which Can Potentially Degrade the Course of a BWR Transient

1. *One or all of the bypass valves fail to modulate open when required.*
2. *One of the bypass valves, which has opened as a result of the transient, fails to close.*
3. *Failure to trip the turbine or feedwater pumps on high water level.*
4. *One main steam isolation valve (MSIV) fails to close when required.*
5. *One of the safety/relief valves fails to open when required.*
6. *One of the safety/relief valves, which has opened as a result of the transient, fails to close.*
7. *Failure to trip one recirculation pump.*
8. *Failure to run back the recirculation pumps.*
9. *Failure of high pressure coolant injection (HPCI) or high pressure core spray (HPCS) or feedwater coolant injection (FWCI) or one isolation condenser (IC) loop, whichever is applicable.*
10. *Failure of reactor core isolation cooling (RCIC) or one IC loop, whichever is applicable.*
11. *Failure of one low pressure coolant injection (LPCI) loop or the low pressure core spray (LPCS) system.*
12. *Loss of one residual heat removal (RHR) system heat exchanger.*
13. *A single control rod stuck while the remainder of the control rods are moving.*
14. *Failure to achieve the rod block function (i.e., a single control rod will withdraw upon erroneous withdrawal demand).*
15. *Loss of one diesel generator if loss of ac power was the initiating event.*

Table II.K.3.44-3

Worst Case of Transient with a Single Failure for Different BWR Product Lines

Product Line	*Transient with a Single Failure (Worst Case)*
BWR/2	*LOF + Failure of one IC loop (Oyster Creek only)* *LOF + Failure of FWCI (Nine Mile Point only)*
BWR/3	*LOF + Failure of FWCI (Millstone only)* *LOF + Failure of HPCI (others)*
BWR/4	*LOF + Failure of HPCI*
BWR/5	*LOF + Failure of HPCS*
BWR/6	*LOF + Failure of HPCS*

Table II.K.3.44-4

Participating Utilities[a]
NUREG-0737

Boston Edison	*Pilgrim 1*
Caroline Power & Light	*Brunswick 1 and 2*
Commonwealth Edison	*LaSalle 1 and 2, Dresden 1-3, Quad Cities 1 and 2*
Georgia Power	*Hatch 1 and 2*
Iowa Electric Light & Power	*Duane Arnold*
Jersey Central Power & Light	*Oyster Creek 1*
Niagara Mohawk Power	*Nine Mile Point 1 and 2*
Nebraska Public Power District	*Cooper*
Northeast Utilities	*Millstone 1*
Philadelphia Electric	*Peach Bottom 2 and 3; Limerick 1 and 2*
Power Authority of the State of New York	*FitzPatrick*
Tennessee Valley Authority	*Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 and 2*
Vermont Yankee Nuclear Power	*Vermont Yankee*
Detroit Edison	*Enrico Fermi 2*
Mississippi Power & Light	*Grand Gulf 1 and 2*
Pennsylvania Power & Light	*Susquehanna 1 and 2*
Energy Northwest	*Columbia Generating Station*
Cleveland Electric Illuminating	*Perry 1 and 2*
Houston Lighting & Power	*Allens Creek*
Illinois Power	*Clinton Station 1 and 2*
Public Service of Oklahoma	*Black Fox 1 and 2*
Long Island Lighting	*Shoreham*

[a] *Report applies to plants included herein whose owners participated in the report development.*

II.K.3.45 Evaluation of Depressurization with Other than Automatic Depressurization System

Position

Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRVs) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown (NUREG-0737).

Clarification

None.

Columbia Generating Station Position

CGS as a member of the BWR Owners' Group endorses the following position statement and analysis prepared by GE on behalf of the Owners' Group.

The evaluation of alternate modes of depressurization other than full actuation of the Automatic Depressurization System (ADS) is made for those plants listed in Table II.K.3.45-5 with regard to the effect of such reduced depressurization rates on core cooling and vessel integrity.

Depressurization by full ADS actuation constitutes a depressurization from about 1050 psig to 180 psig in approximately 3.3 minutes. Such an event, which is not expected to occur more than once in the lifetime of the plant, is well within the design basis of the reactor pressure vessel. This conclusion is based on the analysis of several transients requiring depressurization via the ADS valves. Results of these analyses indicate that the total vessel fatigue usage is less than 1.0. Therefore, no change in the depressurization rate is necessary. However, to comply with the above request reduced depressurization rates were analyzed and compared with the full ADS actuation. The alternate modes considered cause vessel pressure to traverse the same pressure range in (1) depressurization case 1 (ranges from 6-10 minutes depending on plant size and ADS capacity), and (2) depressurization case 2 (ranges from 15-20 minutes). The case 2 depressurization bounds the possible increase in depressurization time by producing an undesirably long core uncovered time. The case 1 depressurization gives the results of an intermediate depressurization. These modes are achieved by opening a reduced number of relief valves. These blowdown rates are illustrated by Figure II.K.3.45-1.

Assumptions:

The major assumptions used for the core cooling analysis are as follows:

a. *No high pressure cooling systems are available,*

b. *All low pressure ECCS is available, and*

c. *Assumptions as stated in NEDO-24708, Section 3.1.1.3, "Justification of Analysis Methods," which includes the use of 1978 ANS Decay Heat (mean value).*

Results:

a. *Vessel Integrity*

The depressurization events considered are full ADS blowdown and blowdown over 10 and 20 minute intervals. The reactor vessel stresses for these events are within the acceptance stress limits defined by ASME Code Section III for emergency conditions (Level C). The core support structures and other safety-related internal components are also within applicable emergency condition stress limits.

The ADS operating conditions which affect fatigue usage of vessel or core support structures are not significantly different for fast and slow blowdown events. Specific calculations of fatigue usage are not required for emergency conditions (Level C). However, available pressure vessel fatigue analyses show the usage per event to be < 0.1 per full ADS event.

In summary, reactor vessel and core support structure integrity is assured for the blowdown rates considered if an ADS event should occur, and reduced rates of depressurization do not significantly decrease fatigue usage.

b. *Core Cooling Capability*

Examination of the reduced depressurization rates under consideration with respect to core cooling concerns shows that:

1. *Vessel depressurization for a case 2 blowdown (15-20 minutes) causes the core to be uncovered for a lengthy period of time even assuming system initiation at the earliest reasonable time.*

2. *Vessel depressurization for a case 1 blowdown (6-10 minutes), when actuated at the same level as the full ADS case, will result in less vessel inventory* at *the time of ECCS injection and can result in longer periods of core uncovery.*

3. *Vessel depressurization for a case 1 blowdown (6-10 minutes) when actuated considerably earlier than at the ADS initiation setpoint can result in some improvement in core cooling. However, the operator is required to act more quickly in these cases (i.e., within 1-6 minutes after the accident). This earlier depressurization also reduces the time available to start high pressure system injection and hence to avoid the need for manual depressurization. It also increases the frequency of depressurization.*

The results of the calculations are presented in Tables II.K.3.45-1 through II.K.3.45-4. They show the total core uncovered time and remaining vessel inventory at the time of low pressure ECCS injection. A discussion of these results follows below.

Discussion:

The results are based upon calculations performed with the assumptions stated earlier using a representative BWR/3 and a BWR/6 to show consistency of results across the product lines. The transients considered are an outside steam line break and a stuck-open relief valve. The ADS will depressurize the vessel to the low pressure ECCS injection setpoint when no high pressure cooling systems are available. The depressurizations used are initiated at different times based on the downcomer water level. The first initiation time considered is when the water level is at the top of the active fuel which is consistent with the original design for most plants and thus is the basis for comparison. The second initiation time considered is the downcomer water level of 34 feet from the bottom of the vessel which still provides the operator with a reasonable time to attempt to start the high pressure systems. The last initiation time considered is the high pressure makeup system setpoint (Level 2 for BWR/6 and Level 1 for BWR/3) plus 60 seconds which is the earliest time in which depressurizaton could be expected to occur.

The core cooling criteria used in assessing the impact of a reduced depressurization rate are:

a. *Inventory in the core and lower plenum at the time of low pressure ECCS injection as predicted by the SAFE model (Reference 1), and*

b. *The total time which the top of the active fuel (TAF) remains uncovered as predicted by the SAFE model (Reference 1).*

The first criterion demonstrates the increased mass loss due to boiloff for the longer blowdown, since mass loss due to flashing will be independent of the depressurization rate providing the boundary pressure values are the same for all the rates. The second criterion is a measure of the resultant core temperature.

Table II.K.3.45-1 gives the results for a BWR/6 assuming an outside steam line break. As the length of depressurization is increased the vessel inventory at the time the ECCS injection decreases and the total core uncovered time increases. Table II.K.3.45-1 further shows that the actuation times based on higher water levels (i.e., 34 ft and Level 2 +60 sec) longer depressurizations exhibit the same trends. Furthermore, for any particular depressurization rate, raising the actuation level increases the vessel inventory at ECCS injection and decreases the total core uncovered time. However, this also decreases the time the operator has available to try to get high pressure level control systems working in order to avoid the need to depressurize.

Table II.K.3.45-2 shows that these same results are exhibited for the case of a stuck-open relief valve. Table II.K.3.45-3 shows the results for a BWR/3 assuming an outside steam line break. Examination of the table shows the same trends as Table II.K.3.45-1, and therefore the results are applicable to all product lines. Table II.K.3.45-4 shows that these general trends are independent of the models used by exhibiting the same trends for a BWR/3 using standard Appendix K licensing assumptions.

Conclusion:

The cases considered show that no appreciable improvement can be gained by a slower depressurization based on core cooling considerations. A significantly slower depressurization rate will result in increased core uncovered time. A moderate decrease in the depressurizaton rate necessitates an earlier actuation time resulting in less time available for operator action to start high pressure ECCS without significant benefit to vessel fatigue usage. This will also result in an increased frequency of ADS actuation.

Finally, it is of paramount importance to note that the ADS is not a normal core cooling system; it is a backup for high pressure cooling systems (feedwater, RCIC, HPCI/HPCS). If ADS operation is ever required in a BWR, it will be because core cooling is threatened. Since a full ADS blowdown is well within the design basis of the reactor pressure vessel and ADS is properly designed to minimize the threat to core cooling, no change in the depressurization rate is necessary.

Reference:

1. *NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August 1979.*

Table II.K.3.45-1

Results for BWR/6 Outside Steam Line Break
No High Pressure Systems Available

Depressurization Case	*Depressurization Initiation*		*Core Uncovered Time (sec)*	*Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)*
	Level	*Time (sec)*		
Full ADS	*TAF*[a]	*1086.0*	*26*	1.603×10^5
Case 1	*TAF*	*1086.0*	*117*	1.528×10^5
Case 1	*34'*	*610.6*	*10*	1.779×10^5
Full ADS	*Level 2*[b] *+60 sec*	*78.3*	*No uncovery*	1.993×10^5
Case 1	*Level 2 +60 sec*	*78.3*	*No uncovery*	1.937×10^5
Case 2	*Level 2*	*78.3*	*390*	1.755×10^5

[a] *Top of active fuel.*
[b] *High pressure initiation setpoint plus 60 sec.*

Table II.K.3.45-2

Results for BWR/6 Stuck-Open Relief Valve
No High Pressure Systems Available

Depressurization Case	Depressurization Initiation: Level	Depressurization Initiation: Time (sec)	Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
Full ADS	TAF[a]	642.6	No uncovery	1.836×10^5
Case 1	TAF	642.6	15	1.787×10^5
Case 1	34'	391.8	No uncovery	1.889×10^5
Case 1	Level 2[b] +60 sec	77.7	No uncovery	1.961×10^5

[a] Top of active fuel.
[b] High pressure initiation setpoint plus 60 sec.

Table II.K.3.45-3

Results for BWR/3 Outside Steam Line Break
No High Pressure Systems Available

Depressurization Case	*Depressurization Initiation*		*Core Uncovered Time (sec)*	*Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)*
	Level	*Time (sec)*		
Full ADS	*TAF*[a]	*1527.8*	*155*	2.027×10^5
Case 1	*TAF*	*1527.8*	*170*	1.975×10^5
Case 1	*34'*	*701.6*	*51*	2.291×10^5
Full ADS	*Level 1*[b] *+60 sec*	*364.4*	*No uncovery*	2.446×10^5
Case 1	*Level 1 +60 sec*	*364.4*	*10*	2.394×10^5

[a] *Top of active fuel.*
[b] *High pressure initiation setpoint plus 60 sec.*

Table II.K.3.45-4

Results for BWR/3 Outside Steam Line Break on Appendix K Assumptions with No High Pressure Systems

Depressurization Case	*Depressurization Initiation*		*Core Uncovered Time (sec)*	*Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)*
	Level	*Time (sec)*		
Full ADS	*TAF*[a]	*759.4*	*264*	1.960×10^5
Case 1	*TAF*	*759.4*	*277*	1.913×10^5
Full ADS	*Level 1*[b] *+60 sec*	*145.6*	*175*	2.210×10^5
Case 1	*Level 1 +60 sec*	*145.6*	*191*	2.165×10^5

[a] *Top of active fuel.*
[b] *High pressure initiation setpoint plus 60 sec.*

Table II.K.3.45-5

Participating Utilities [a]
NUREG-0737

Boston Edison	*Pilgrim 1*
Caroline Power & Light	*Brunswick 1 and*
Commonwealth Edison	*LaSalle 1 and Dresden 2 and Quad Cities 1and 2*
Georgia Power	*Hatch 1 and 2*
Iowa Electric Light & Power	*Duane Arnold*
Jersey Central Power & Light	*Oyster Creek 1*
Niagara Mohawk Power	*Nine Mile Point 1 and 2*
Nebraska Public Power District	*Cooper*
Northeast Utilities	*Millstone 1*
Northern States Power	*Monticello*
Philadelphia Electric	*Peach Bottom 2 and 3; Limerick 1 and 2*
Power Authority of the State of New York	*FitzPatrick*
Tennessee Valley Authority	*Browns Ferry 1-3; Hartsville1-4, Phipps Bend 1 and 2*
Vermont Yankee Nuclear Power	*Vermont Yankee*
Detroit Edison	*Enrico Fermi 2*
Long Island Lighting	*Shoreham*
Mississippi Power & Light	*Grand Gulf 1 and 2*
Pennsylvania Power & Light	*Susquehanna 1 and 2*
Energy Northwest	*Columbia Generating Station*
Cleveland Electric Illuminating	*Perry 1 and 2*
Houston Lighting & Power	*Allens Creek*
Illinois Power	*Clinton Station 1and 2*
Public Service of Oklahoma	*Black Fox 1 and 2*

[a] *Report applies to plants included herein whose owners participated in the report development.*

II.K.3.46 Response to List of Concerns from ACRS Consultant (Michelson Concerns)

Position

General Electric should provide a response to the Michelson concerns as they relate to BWRs. See NUREG-0660, Appendix C, Table c.3, Item 46 (Reference 1) and NUREG-0626, Section 4, Item A.17 (Reference 6c).

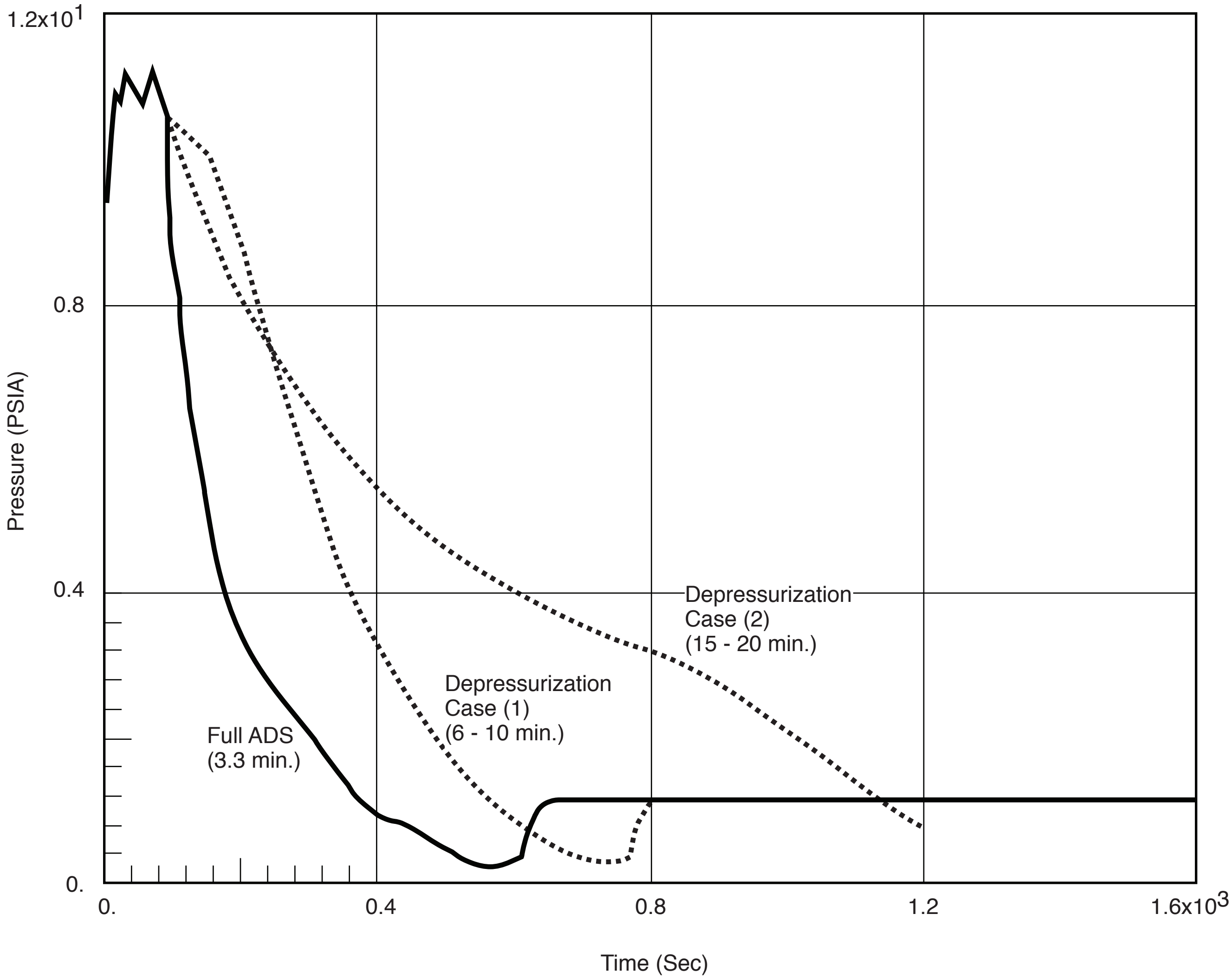
Clarification

None.

Columbia Generating Station Position

GE, acting for the BWR Owners' Group, responding to these concerns in a letter, "Response to Questions Posed by Mr. C. Michelson," R. H. Buchholz (GE) to D. F. Ross, dated February 21, 1980. Submittal of this letter completes the action required by this task.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, Section 6.3.6.



Columbia Generating Station
Final Safety Analysis Report

Vessel Blowdown Rates Used in Analysis

Draw. No. 990578.72	Rev.	Figure II.K.3.45-1

III.D.1.1 Primary Coolant Sources Outside Containment

Position (Full Power License Requirement)

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:

a. Immediate Leak Reduction

   1. Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

   2. Measure actual leakage rates with system in operation and report them to the NRC.

b. Continuing Leak Reduction

   1. 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.

Dated Requirement

Applicants shall submit the information requested in the "Clarification" section of this position at least 4 months prior to issuance of a fuel-loading license.

This requirement shall be implemented by applicants for operating license prior to issuance of a full-power license. See NUREG-0737, Section III.D.1.1.

Clarification

Applicants shall provide a summary description, together with initial leak-test results, of their program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident.

a. 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 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.

b. Testing of gaseous systems should include helium leak detection or equivalent testing methods.

c. 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.

This requirement applies to all operating license applicants.

Columbia Generating Station Position

Columbia Generating Station has performed a systems design review and established criteria for a surveillance/preventive maintenance program to limit to as-low-as-practical, leakage from systems outside containment which could transport highly radioactive fluids during a serious transient or accident.

a. Systems Review

The systems for leak paths for primary coolant outside containment showed three potentially unisolated leak paths which could contain highly radioactive fluids during a serious accident or transient. These three leak paths originate at the reactor building sumps with a transport pathway to the waste collection tanks in the radwaste building. The three leak path lines have been addressed in a licensing technical change. Dual auto-isolation valves have been added to each of the three lines along with accompanying isolation logic.

b. Leakage Monitoring

A leakage surveillance and preventive maintenance program* for those systems within secondary containment which could transport highly radioactive fluids in the case of a serious reactor transient or accident has the following features.

1. Designation of systems included within the leakage surveillance and preventive maintenance program:

   (a) Residual Heat Removal,
   (b) Reactor Core Isolation Cooling,
   (c) High Pressure Core Spray,
   (d) Low Pressure Core Spray,
   (e) Primary Containment Atmospheric Control,
   (f) Primary Containment Atmospheric Monitoring,
   (g) Post Accident Sampling.

2. A system list which identifies the components to be inspected, the method of inspection or measurement, and the surveillance frequency.

3. Routine inspections by operators of visually accessible portions of designated systems during normal operating conditions or test mode.

4. Detailed leakage inspection and measurement defined for designated systems during initial test program and thereafter.

5. An aggressive preventive maintenance program with high priority assigned to leakage-related work or designated systems.

6. A review cycle for leakage-related work requests to evaluate possible modifications to keep leakage as low as is reasonably achievable.

III.D.3.3 *Improved Inplant Iodine Instrumentation Under Accident Conditions*

Position *(NUREG-0737)*

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.

* This program takes exception for those systems which cannot be tested until startup due to required plant conditions. Program documentation will be available onsite for NRC I&E review.

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 ziolite) 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.

<u>Columbia Generating Station Position</u>

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for this instrumentation in the following sections: 7.5.2.2.3, 12.3.4.2, 12.3.4.4, 12.5.2.1, 12.5.3.5, and Emergency Plan Section 8.7.5.

Columbia Generating Station is responding to this position as follows: Four fixed, one mobile continuous air monitoring system, and one movable local alarming continuous air monitor are provided for air sampling in plant areas where personnel may be present during accident conditions. In addition, 10 low volume air sampling systems will be strategically located throughout the plant in frequently occupied areas to continuously draw air samples for subsequent analysis.

Grab samples will be obtained using varying volume air samplers that are both ac and dc powered.

Movable local alarming continuous air monitors are placed at predetermined plant locations for personnel protection and to substantiate the quality of the plant breathing atmosphere. These monitors have local readouts (charts) and radioiodine sampling capabilities.

Energy Northwest is currently using activated charcoal cartridges for radioiodine analysis and is evaluating the attributes of silver zeolite. On completion of a satisfactory evaluation Energy Northwest will, where applicable, incorporate silver zeolite into its air sampling program. The charcoal cartridges are used in conjunction with a Ge (Li) gamma spectroscopy system located in a low background, low contamination area such as the radiochemistry lab in the near site facility. Prior to analysis, cartridges are purged in a fume hood using plant air, instrument air, bottled air, or bottled nitrogen which is stored onsite.

Station procedures are provided for obtaining and evaluating both routine and non-routine air samples. In addition to initial training provided for Health Physics/Chemistry personnel, periodic drills are conducted in accordance with the Emergency Plan.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated December 1982, Section 12.5.2.