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SUBJECT: Forwards App. 8 to FSAR "Response to Regulatory Issues Resulting From TMI-2." App is part of Amend 17, which will be sent within 1 month. All repts

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Docket No. 50-397

July 31, 1981
G02-81-219
NS-L-02-CDT-81-018

Director, Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington D.C. 20555

Attention: Mr. A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing

Gentlemen:

Subject: SUPPLY SYSTEM NUCLEAR PROJECT NO. 2
FSAR APPENDIX B - WNP-2 RESPONSE TO
REGULATORY ISSUES RESULTING FROM TMI-2

Enclosed are sixty (60) copies of Appendix B to the WNP-2 FSAR, "WNP-2 Response to Regulatory Issues Resulting From TMI-2". This appendix is a part of FSAR Amendment 17 which will be distributed to you within one month.

Very truly yours,

G D Bouchey

G. D. BOUCHEY
Director, Nuclear Safety

GDB:CDT:ct

Enclosure

cc: WS Chin, BPA
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AD Toth, NRC, Resident Inspector
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WNP-2 Files
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APPENDIX B

WNP-2 RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

APPENDIX B

WNP-2 RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

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I.A.1.1 Shift Technical Advisor

Position (NUREG-0737)

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

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

Clarification

The letter of October 30, 1979 clarified the short-term STA requirements. That letter indicated that the STAs must have completed all training by January 1, 1981. This paper confirms these requirements and requests additional information.

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

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

Since the October 30, 1979 letter was issued, several efforts have been made to establish, for the longer term, the minimum

level of experience, education, and training for STAs. These efforts include work on the revision to ANS-3.1, work by the Institute of Nuclear Power Operations (INPO), and internal staff efforts.

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

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

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

WNP-2 Position

For the short term, WNP-2 will provide qualified and trained engineers who will be assigned on shift (as required) to perform the STA function. The engineers will be from the Plant Technical staff and will meet the intent of the qualifications, education, experience, and training requirements presented in the INPO documents, dated April 18, 1980, titled "Nuclear Power Plant Shift Technical Advisor."

For the long term, WNP-2 plans to upgrade the qualifications and training of the shift supervisors and senior reactor operators and upgrade the man-machine interface in the control room, thereby eliminating the requirement for providing the STA function by Technical staff engineers.

A detailed description of the training program will be provided by April 1982.

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 assure 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 assuring 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 assuring 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.

WNP-2 Position

The administrative duties of the shift supervisor will be reviewed. Inappropriate functions will be delegated to other personnel to meet the intent of this position. Appropriate documentation will be available on site for review by NRC I&E by July 1982.

TABLE I.A.1.2-1

SHIFT SUPERVISOR RESPONSIBILITY (2.2.1.A)

NUREG-0578 POSITION (POSITION NO.)	CLARIFICATION
Highest Level of Corporate Management (1.)	V. P. For Operations
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 Supervisor 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

TABLE I.A.1.2-1 (Continued)

NUREG-0578 POSITION (POSITION NO.)	CLARIFICATION
Administrative Duties Reviewed (4.)	On Same Interval as Reinforcement: i.e., Annual by V. P. for Operations

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

I.A.1.3 Shift Manning

Position

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

Clarification

Page 3 of the July 31, 1980 letter is superseded in its entirety by the following:

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

These administrative procedures shall also set forth a policy, the objective of which is to operate the plant with the required staff and develop working schedules such that use of overtime is avoided, to the extent practicable, for the plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, health physicists, auxiliary operators, I&C technicians and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions (see WNP-2 position).

The staff recognizes that there are diverse opinions on the amount of overtime that would be considered permissible and that there is a lack of hard data on the effects of overtime beyond the generally recognized normal 8-hour working day, the effects of shift rotation, and other factors. The NRC has initiated studies in this area. Until a firmer basis is developed on working hours, the administrative procedures shall include as an interim measure the following guidance, which generally follows that of IE Circular No. 80-02.

In the event that overtime must be used (excluding extended periods of shutdown for refueling, major maintenance or major plant modifications), the following overtime restrictions should be followed:

a. An individual should not be permitted to work more than 12 hours straight (not including shift turnover time).

b. There should be a break of at least 12 hours (which can include shift turnover time) between all work periods.

c. An individual should not work more than 72 hours in any 7-day period.

d. An individual should not be required to work more than than 14 consecutive days without having 2 consecutive days off.

However, recognizing that circumstances may arise requiring deviation from the above restrictions, such deviation shall be authorized by the plant manager or his deputy, or higher levels of management in accordance with published procedures and with appropriate documentation of the cause.

If a reactor operator or senior reactor operator has been working more than 12 hours during periods of extended shutdown (e.g., at duties away from the control board), such individuals shall not be assigned shift duty in the control room without at least a 12-hour break preceding such an assignment.

The NRC encourages the development of a staffing policy that would permit the licensed reactor operators and senior reactor operators to be periodically assigned to other duties away from the control board during their normal tours of duty.

If a reactor operator is required to work in excess of 8 continuous hours, he shall be periodically relieved of primary duties at the control board, such that periods of duty at the board do not exceed about 4 hours at a time.

The guidelines on overtime do not apply to the shift technical advisor provided he or she is provided sleeping accommodations and a 10-minute availability is assured.

Operating license applicants shall complete these administrative procedures before fuel loading. Development and implementation of the administrative procedures at operating plants will be reviewed by the Office of Inspection and Enforcement, beginning 90 days after July 31, 1980.

See Section III.A.1.2 for minimum staffing and augment capabilities for emergencies.

WNP-2 Position

Minimum Shift Crew:

Minimum shift manning for WNP-2 will consist of the following:

a. One Shift Manager (shift supervisor) with a senior reactor operator's license (SRO) on site at all times when the reactor contains fuel.

b. A Control Room Supervisor with a senior reactor operator's license (SRO) in the control room at all times when the reactor is in power operation, startup, or hot shutdown (conditions 1, 2, and 3). This Control Room Supervisor may, from time to time, be relieved by the Shift Manager (item a, above) or by any other licensed senior reactor operator.

c. A licensed reactor operator (RO) in the control room at all times when the reactor contains fuel.

d. One additional licensed reactor operator (RO) shall be on site at all times when the reactor is in power operation, startup, or hot shutdown (conditions 1, 2 and 3). This individual may serve as relief operator for the control room, when the reactor is operating.

e. Two equipment (non-licensed) operators shall be on site at all times when the reactor is in power operation, startup, or hot shutdown. At least one equipment (non-licensed) operator shall be on site at all times when the reactor contains fuel.

f. During core alterations, an additional licensed senior reactor operator (SRO) or limited senior reactor operator (SROL) to directly supervise the core alterations. The SRO or SROL may have fuel handling duties but shall not have other concurrent operational duties.

Staffing Plan:

Shift coverage is provided by utilizing a rotating shift schedule depending on operating needs and bargaining unit contractual requirements. The schedules are based on a 40-

hour work week and shifts are normally 8-hour duration (excluding shift turnover time).

To assure that sufficient SRO and RO licensed individuals are available as required for plant operation, we are preparing, for cold license exams, an adequate number of SRO and RO shift personnel to support a six crew rotation plus additional management and training SRO candidates. We anticipate a high success rate and therefore expect no problem in maintaining a sufficient number of licensed individuals to meet the minimum manning requirements.

Overtime and Work Hours:

It shall be WNP-2 policy to maintain an adequate number of personnel in the Shift Manager, Control Room Supervisor, Shift Technical Advisor (if required), Control Room Operator, and Equipment Operator positions such that the use of overtime is not routinely required to compensate for inadequate staffing. Administrative procedures, prepared by July 1982, will document our policy concerning the use of overtime work.

The administrative procedures will also stipulate that work schedules for the Shift Manager, Control Room Supervisor, Shift Technical Advisor (if required), Control Room Operators, and Equipment Operators shall be established in advance to ensure that the potential for exceeding the following guidelines is minimized when filling the minimum shift manning requirements previously defined; that is:

a. No individual should work more than 12 consecutive hours. This does not include time necessary for shift turnover.

b. No individual should work more than 24 hours in any 48-hour period.

c. No individual should work more than 72 hours in any 7-day period.

d. No individual should work more than 14 consecutive days without having two consecutive days off.

It should be noted that vacancies due to resignation, promotion, unexpected illness, time off for personal business, or other uncontrollable factors may create situations requiring extended overtime outside these guidelines. Such deviations shall be corrected as soon as possible. Those instances resulting in deviations will be documented and reviewed by the

Plant Manager or his designee as soon as practicable following the occurrence.

I.A.2.1 Immediate Upgrading of Operator and Senior Operator Training and Qualification

Position (NUREG-0737)

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

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

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

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

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

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

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

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

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

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

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

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

Clarification

None

WNP-2 Position

The intent of the above position will be implemented for WNP-2 when operator license submittals are made. If it should become necessary or desirable to deviate from the experience levels identified as prerequisite for SRO Licensing, this deviation shall be identified and justified as a part of the individual's license application.

I.A.2.3 Administration of Training Programs for Licensed Operators

Position

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

Clarification

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

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

The requirement is directed to permanent members of the training staff that teach the subjects enumerated above, including members of other organizations who routinely conduct training at the facility. There is no intention to require guest lecturers who are experts in particular subjects (reactor theory, instrumentation, thermo-dynamics, health physics, chemistry, etc.) to successfully complete a senior operator examination. Nor do we intend to require a system expert, such as the Instrument and Control Supervisor teaching the rod control drive system to sit for a senior operator examination. The use of guest lecturers should be limited.

WNP-2 Position

Applications for SRO examinations of Training Engineers who teach license candidates and/or licensed Operators will be submitted prior to July 1982. These instructors will have participated in the Cold License Training Programs and will continue to participate in appropriate retraining or requalification programs as either instructor or student.

The requirement is directed to permanent members of the Training Department that teach the subjects enumerated above, including members of other organizations who routinely conduct extensive training at the facility. WNP-2 does not intend to require guest lecturers who are experts in particular subjects

(reactor theory, electrical theory, instrumentation, thermodynamics, health physics, chemistry, etc.) to successfully complete a Senior Operator Exam. Nor does WNP-2 intend to require a system or component expert, such as the Instrument and Electrical Supervisor teaching the rod drive control system, to sit for a Senior Operator Examination. Use of guest lecturers will be limited so that program continuity can be maintained.

I.A.3.1 Revise Scope and Criteria for Licensing Examinations - Simulator Exams

Position

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

Changes to Previous Requirements and Guidance: The administration of simulator examinations will be deferred for applicants whose facilities do not have simulators on site as of October 1, 1980. These deferred simulator examinations will be initiated by October 1, 1981.

Clarification

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

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

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

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

Utility companies should make the necessary arrangements with an appropriate simulator training center to provide time for these examinations. Preferably these examinations should be scheduled consecutively with the balance of the examination. However, they may be scheduled no sooner than 2 weeks prior to and not later than 2 weeks after the balance of the examination.

WNP-2 Position

The new subject matter and grading criteria have been implemented in the Cold License Simulator Training classes being conducted for WNP-2 by the General Physics Corporation.

The requirement for applicants for operator licenses to grant permission for the NRC to inform facility management regarding results of the examinations will be implemented just prior to the administration of these exams.

The simulator for WNP-2 may not be available to support simulator examinations for the initial operating staff. In this event, WNP-2 has arranged to conduct these examinations at another simulator facility. Scheduling with the NRC for the simulator examinations will be made as part of the normal scheduling of license examinations.

I.B.1.2 Independent Safety Engineering Group

Position

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

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

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

Clarification

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

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

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

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

WNP-2 Position

The Supply System has established a Nuclear Safety Assurance group for WNP-2 within the Licensing and Assurance Directorate as shown in Figure I.B.1.2-1. The onsite Nuclear Safety Assurance group (comprised of a minimum of one supervisor and two engineers) is supplemented by offsite technical expertise from within the Licensing and Assurance Directorate as required with a minimum of two qualified engineers available to support the WNP-2 assurance group. The WNP-2 Nuclear Safety Assurance group is independent of the line management responsible for power production and chartered with ensuring and improving operational nuclear safety of the WNP-2 plant.

The functions of the WNP-2 Nuclear Safety Assurance group include the following:

a. Evaluation of procedures important to safe operation of WNP-2 for technical adequacy and clarity.

b. Evaluation of plant operations from a safety perspective.

c. Evaluation of the operating experience of WNP-2 to provide recommendations on safety-related concerns. In this regard operating experience of other plants of similar design is assessed for applicability to WNP-2.

d. Overall assessment of WNP-2 plant performance regarding conformance to safety requirements.

e. Other matters relating to safe operation of WNP-2 that independent review deems appropriate for consideration.

The qualification and training requirements for the Nuclear Safety Assurance Manager are comparable to that described in Section 4.2 of ANS 3.1, Draft Revision, dated March 13, 1981. Other qualifications and training requirements meet ANS 3.1, Draft Revision, dated March 13, 1981, Section 4.2 or 4.4 or equivalent as described in Section 4.1.

WNP-2 Position

The Supply System plans to provide an on-site Safety Engineering Group for WNP-2 consisting of four dedicated full-time engineers. This group will be part of the Nuclear Safety Organization shown in Figure I.B.1.2-2 that reports directly to the Managing Director. The Nuclear Safety Organization is chartered with ensuring and improving overall nuclear safety of Supply System nuclear facilities and has no direct responsibility for day-to-day power production. The on-site safety engineers will be supported by off-site independent engineering and safety expertise as required to accomplish their functions. The WNP-2 Safety Engineering Group will be established and staffed sufficiently in advance of fuel loading to allow orientation of the staff and review of plant operating procedures prior to their use.

The general functions of the WNP-2 Safety Engineering Group will include the following:

a. Evaluation of procedures important to safe operation of WNP-2 for technical adequacy and clarity.

b. Evaluation of plant operations from a safety perspective.

c. Evaluation of the operating experience of WNP-2 to provide recommendations on safety-related concerns. In this regard operating experience of other plants of similar design will be assessed for applicability to WNP-2.

d. Overall assessment of WNP-2 performance at WNP-2 regarding conformance to safety requirements.

e. Other matters relating to safe operation of WNP-2 that independent review seems appropriate for consideration.

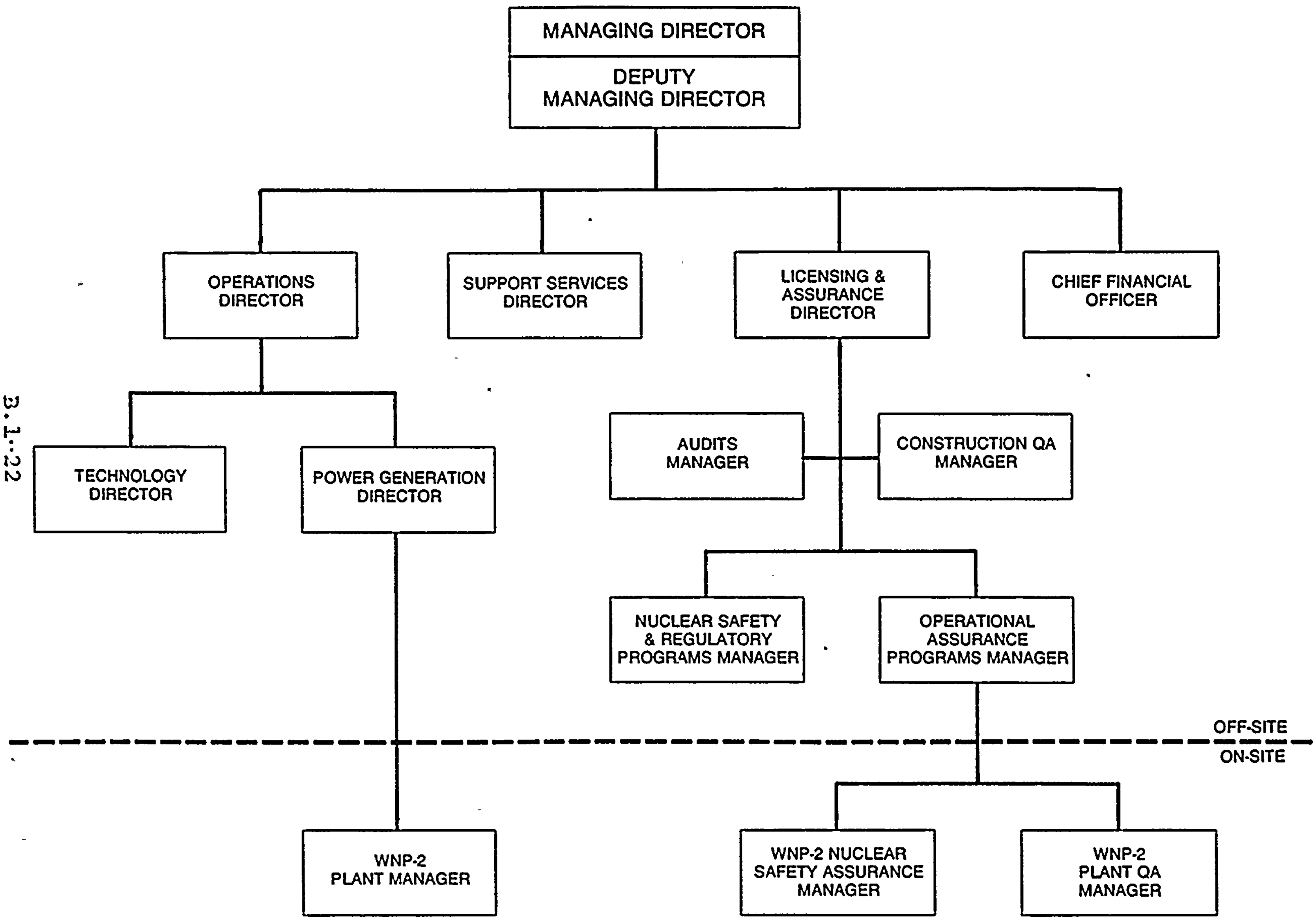
f. Assessment of plant safety programs.

The qualification and training of the SEG Manager will be comparable to that described in Section 4.2 of ANS 3.1, draft revision, dated March 13, 1981. Other SEG member qualifications and training will meet ANS 3.1, draft revision, dated March 13, 1981, Section 4.2, 4.4 or 4.5, or equivalent, as described in Section 4.1.

Considering the number of Supply System nuclear plants now under construction, the Supply System considers that the safety review function can be best served by having highly qualified experts in disciplines (which would not be fully utilized at one site) available in the independent Nuclear Safety Organization and other off-site centralized technical organizations to support all sites on an ad hoc basis. This would be particularly true for personnel in fields where there are few qualified people available. The technical assets of the company will be available as needed and when necessary specialists will be assigned to the Director of Nuclear Safety to support plant safety evaluations.

The concept and specific role of a dedicated on-site safety group is expected to evolve as experience is obtained with this approach. The Supply System will continue to evaluate this approach and it is expected that we may need to modify the functions, role or organizational approach of this group consistent with effective utilization of resources and improving overall safety and efficiency of our plants.

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2



NUCLEAR SAFETY ASSURANCE ORGANIZATION

FIGURE I.B.1.2-1

AMENDMENT NO. 30
June 1983

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

WNP-2 Position

WNP-2 has participated, and continues to participate, in the BWR Owners' 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 feed water 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 FSAR 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 noncondensibles; 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 valve 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 FSAR 3.1.1, 3.2.1, and 3.5.2.1).

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

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

2. BWR Emergency Procedure Guidelines (Revision 1) - submitted on January 31, 1981.

   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 paragraph a have been discussed and reviewed extensively among the BWR Owners' 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 plants with applications for operating licenses pending)."

WNP-2 believes that in view of these findings, no further detailed justification of the analyses 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 to Reference 1 identifies several such areas. WNP-2 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.

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 assure the following:

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

   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

WNP-2 Position

The directives and procedures necessary to meet the intent of the position are being prepared and will be implemented prior to July 1982. These procedures will be made available on site for review by NRC I&E.

I.C.3 SHIFT SUPERVISOR RESPONSIBILITY

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 assure 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 the shift supervisor is to provide for assuring 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 assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

Clarification

The attachment provides clarification to the above position.

WNP-2 Position

The administrative duties of the shift supervisor have been reviewed. Inappropriate functions were delegated to other personnel.

WNP-2 procedures were reviewed to ensure that the shift manager, control room supervisor, and operator funcions are defined adequately to establish the shift manager in the control room as the commanding authority for plant operations relative to other plant management.

This principle is reinforced by a management directive issued annually from the office of the Director of Generation that emphasies that the shift manager's primary responsibility is the safe operation of the plant under all conditions.

The shift manager's administrative duties are reviewed annually by the plant manager to ensure that administrative responsibilities do not interfere with the primary responsibility.

Appropriate documentation is available onsite for review by NRC I&E Branch.

TABLE I.C.3-1

SHIFT SUPERVISOR RESPONSIBILITY (2.2.1.A)

NUREG-0578 POSITION (POSITION NO.)	CLARIFICATION
Highest Level of Corporate Management (1.)	V. P. For Operations
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 (2.8)	Formal Transfer of Authority, Valid SRO License, Recorded in Plant Log
Temporarily Absent (2.C)	Any Absence
Control Room Defined (2.C)	Includes Shift Supervisor 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 V. P. for Operations

This requirement shall be met prior to July 1982. See NUREG-0578, Section 22.1a, Item 4 and NRC letters of September 27 and November 9, 1979.

I.C.4 CONTROL ROOM ACCESS

Position (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

WNP-2 Position

A WNP-2 procedure has been prepared and 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 utilized to enforce the policy.

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.5 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO PLANT STAFF

Position

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

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

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

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

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

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

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

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

Clarification

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

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

WNP-2 Position

The WNP-2 plant will have procedures covering the review and feedback of operating experiences. These procedures will be in effect at the time of fuel load and will be made available for onsite review by NRC I&E.

The following summary presents the essence of the final procedure(s):

a. The WNP-2 Nuclear Safety Assurance group initiates a review of operating experience material utilizing technical expertise within the Supply System as appropriate. Extraneous and unimportant information is sorted out and conflicting opinions resolved.

b. Following this review, the WNP-2 Nuclear Safety Assurance Manager supplies detailed information to the appropriate section manager for dissemination to identified recipients (supervisory personnel, STAs, operators, maintenance personnel, health physics technicians, etc.).

c. It is the responsibility of the appropriate section manager receiving the operating experience information to provide the information to the training section for inclusion in the retraining program and to disseminate the information directly to the identified recipients if a more rapid transmittal is appropriate.

d. The WNP-2 Nuclear Safety Assurace Manager, with assistance from the appropriate section manager, makes recommendations to the Plant Manager on the need for procedure changes or plant modifications identified from the operating experience review. Those changes deemed appropriate by the Plant Manager are then processed as described in the Plant Administrative Procedures.

e. The WNP-2 Training Manager is responsible for incorporating into the training program the information received from the operating experience review program. To prevent conflicting or contradictory information being conveyed to plant personnel, the Training Manager clears through the WNP-2 Nuclear Safety Assurance Manager any operating expirence information received from other sources.

f. The WNP-2 Nuclear Safety Assurance Manager is responsible for periodic surveillance of the entire operating experience review process. Particular attention is paid to appropriate and timely incorporation of procedure change and plant modification recommendations resulting from the review of operating experiences. Operational QA periodically audits the operating experiences review program.

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

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

Clarification

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

The American Nuclear Society has prepared a draft revision to ANSI Standard N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." A second proposed revision to Regulatory Guide 1.33, "Quality Assurance Program Requiremments (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 on-shift SRO, provided provisions are made to ensure that the shift supervisor is kept fully informed of system status.

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

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 can prove that all equipment, valves, and switches involved in the activity are correctly aligned.

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

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

<u>WNP-2 Position</u>

WNP-2 will prepare the directives and procedures necessary to implement an effective system of verification of operating activities important to safety prior to July 1982. This program will include both automatic status monitoring and human verification by a qualified second person. We do not, however, consider it necessary to verify implementation of equipment ~~operability~~ by use of a licensed operator. Proper return-to-service of safety-related equipment will be emphasized and will be accomplished either by functional testing, automatic status monitoring, or by verification by a second qualified person.

tagging

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

WNP-2 Position

The NSSS vendor (General Electric Company) will review and document the low power testing, power ascension test, and emergency procedures by July 1982. This review will consider the BWR Emergency Procedure guide-lines submitted to the NRC on behalf of a BWR Owners' Group on June 30, 1980, by letter from R. H. Buchholz to D. G. Eisenhut.

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

Position

Correct emergency procedures, as necessary, based on the 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, steamline break, or steam-generator tube rupture).

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

Clarification

None

WNP-2 Position

WNP-2 will have procedures based on the BWR Emergency Procedure Guidelines by April 1982. These procedures are further addressed in response to I.C.1, Short-Term Accident Analysis and Procedure Revision.

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 modifications 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;

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.

WNP-2 Position

WNP-2 has undertaken an aggressive program to complete a control room review program in accordance with this task. A report entitled "WNP-2 Preliminary Control Room Human Engineering Design Report," dated December 1981, provides a detailed description of the control room review efforts completed to date and future plans associated with this task.

I.D.2 PLANT SAFETY PARAMETER DISPLAY CONSOLE

Position

In accordance with Task Action Plan I.D.2, Plant Safety Parameter Display Console (NUREG-0660), each applicant and licensee shall install a safety parameter display system (SPDS) that will display to operating personnel a minimum set of parameters which define the safety status of the plant. This can be attained through continuous indication of direct and derived variables as necessary to assess plant safety status (NUREG-0737).

Clarification

These requirements for the SPDS are being developed in NUREG-0696, which is scheduled for issuance in November 1980.

WNP-2 Position

FSAR 7.5.1.5, 7.5.1.6, and 7.7.1.15 describe the SPDS and supporting technical data aquisition system to be implemented on WNP-2 in response to this issue. WNP-2 is working with the BWR Owners' Group to develop the emergency response information system (ERIS) as the BWR utility position responding to the concerns of Item I.D.2. The combination of these descriptions and the implementation of the ERIS concept adequately answers the concerns of Item I.D.2.

DELETED

Insert following sentence on Page 8.1-43:

The detailed design and extent to which the intent of the requirements provided in NUREG-0696 will be provided in the next FSAR amendment.

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 experiences 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 requirement. 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

WNP-2 Position

The Supply System is committed to meet the intent of NUREG-0660 by performance of a special low power test subprogram which provides supplemental operator training in the areas of response to abnormal plant conditions and familiarity with critical systems. The special subprogram will amplify the well-established training value of the present Startup Test Program (STP) through (1) instruction on the content, goals, and requirements of the existing program, (2) addition of selected special tests to the STP to demonstrate abnormal scenarios and use of critical systems and/or emergency operating procedures to control them, and (3) utili-

zation 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 will be intimately involved in the performance of the various test procedures. With the impetus provided by the responsible test phase organization, the operations staff is 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 provides the physical ability to accomplish the Startup Test Program. In this fashion, the completion of the Startup Test Program provides an unparalleled training opportunity for the operators.

The following outlines those additional actions the Supply System will implement 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 of the Actual STP Results vs. Anticipated Results

2) 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) RHR Steam Condensing Mode Operation

6) Feedwater Level Setpoint Changes

III. Utilization of the STP Data

A. Refine the WNP-2 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 is anticipated that every pertinent member of the operations staff will obtain valuable knowledge and experience through participation in the WNP-2 Startup Test Program. Each will receive appropriate classroom instruction; through judicious scheduling of tests, most will obtain personal exposure to a variety of plant/system transient responses (or review of results thereof); and the training received will be continually re-enforced through normal requalification program refinements. Future license candidates will also benefit from the training material upgrades resulting from the STP experience.

With this program outline, the Supply System is meeting the intent of NUREG-0660, Item I.G.1. Specific details of the training program, additional test procedures, and documentation methods will be developed and made available for onsite NRC I&E review prior to July 1982.

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 noncondensible gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the events shall conform to the requirements of Appendix A to 10 CFR Part 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that assures 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 loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10 CFR 50.46.

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 noncondensible gas which could interfere with core cooling.

2. Procedures addressing the use of the reactor coolant system vents should define the conditions under which the vents should be used

as well as the conditions under which the vents should not be used. The procedures should be directed toward achieving a substantial increase in the plant being able to maintain core cooling without loss of containment integrity for events beyond the design basis. The use of vents for accidents within the normal design basis must not result in a violation of the requirements of 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 noncondensible gas to be vented and in a specific venting time. For containments particularly vulnerable to failure from large hydrogen releases over a short period of time, the necessity and desirability for contained venting outside the containment must be considered (e.g., into a decay gas collection and storage system).

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

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

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

7. Since the reactor coolant system vent will be part of the reactor coolant system pressure boundary, all requirements for the reactor pressure boundary must be met, and, in addition, sufficient redundancy should be incorporated into the design to minimize the probability of an inadvertent actuation of the system. Administrative procedures, may be a viable option to meet the single-failure criterion. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 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 noncondensible 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 noncondensible 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 noncondensible gas from the reactor vessel hot legs (to the elevation of the top of the outlet nozzle) and cold legs (through head jets and other leakage paths).

2. Additional venting capability is required for those portions or 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 assures 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 assure its availability for system pressure and volume control. These are important considerations, especially during natural circulation.

WNP-2 Position

Since the purpose of the Reactor Coolant System (RCS) vents is to vent noncondensible gases from the RCS which may inhibit core cooling during natural circulation, this requirement is not applicable to WNP-2. The design of the WNP-2 Reactor Pressure Vessel (RPV) (as described in Chapter 4), precludes noncondensible gases from inhibiting natural circulation cooling of the core. The gases which may be generated from the core would collect in the reactor dome above the water which covers the core. Natural circulation through the core would continue unaffected by the noncondensible gases in the reactor vessel dome. Hence, venting of the reactor coolant system is not necessary to ensure continued natural circulation.

II.B.2 DESIGN REVIEW OF PLANT SHIELDING AND ENVIRONMENTAL QUALIFICATION OF EQUIPMENT FOR SPACES/SYSTEMS WHICH MAY BE USED IN POST-ACCIDENT OPERATIONS

Position

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

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

Clarification

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

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

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

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

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

a. Source Term:

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

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

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

b. Systems Containing the Source:

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

c. Dose Rate Criteria:

The design dose rate for personnel in a vital area should be such that the guidelines of GDC 19 will not be exceeded during the course of the accident. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel should not be in excess of 5 rem whole body, or its equivalent to any part of the body for the duration of the accident. When determining the dose to an operator, care must be

taken to determine the necessary occupancy times in a specific area. For example, areas requiring continuous occupancy will require much lower dose rates than areas where minimal occupancy is required. Therefore, allowable dose rates will be based upon expected occupancy, as well as the radioactive source terms and shielding. However, in order to provide a general design objective, we are providing the following dose rate criteria with alternatives to be documented on a case-by-case basis. The recommended dose rates are average rates in the area. Local hot spots may exceed the dose rate guidelines. These doses are design objectives and are <u>not</u> to be used to limit access in the event of an accident.

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

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

d. Radiation Qualification of Safety-Related Equipment:

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

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

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

The following table summarizes these considerations:

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

<u>WNP-2 Position</u>

WNP-2 concurs with this task as presented in NUREGs 0578, 0660, and 0694. NUREG-0578 states that the review shall be done "with the assumption of a post-accident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 ..." NUREG-0660 states, NRR will require " a radiaton and shielding design review of spaces around systems in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by radiation during operation following an accident resulting in a degraded core..." NUREG-0694 requests that a "radiation and

shielding design review that identifies the location of vital areas and equipment in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by radiation during operations following an accident resulting in a degraded core ..." be provided as a condition for issuance of a full power license. The NUREG-0660 clarification letter of September 5, 1980 expands on the post-accident/ degraded core scenario.

WNP-2 performed the review as specified by the referenced NUREGs by using in-house personnel the architect/engineer and consultant. As a product of this review, WNP-2 produced an interim Shielding Evaluation Radiation Report (submitted to the NRC in January 1982) and a Final Shielding Evaluation Radiation Report (submitted in November 1982). These reports addressed all the issues needed to comply with the II.B.2 position except as follows: WNP-2 takes exception to the portion of this task that specifies that a review of "safety-related equipment which may be degraded by radiation during post-accident operation be provided for a non-LOCA, High-Energy Line Break Source Term." The pipe break/missile analysis performed in 3.5 and 3.6 of the FSAR addresses non-mechanistic pipe breaks inside the outside containment. These pipe breaks do not lead mechanistically to a radiation release due to fuel failures beyond those allowed in normal operation. Hence, the source term identified applied outside containment is entirely hypothetical and would be a new design basis beyond the scope of current regulations.

II.B.3 POST-ACCIDENT 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 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18-3/4 rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

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

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

c. Reactor coolant and containment atmosphere sampling during post-accident conditions shall not require an isolated auxiliary system (e.g., the letdown system, reactor water cleanup system (RWCS)) to be placed in operation in order 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 upon 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 con-

ditions the licensee shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

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 GDC 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10 CFR Part 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979 letter from H. R. Denton to all licensees.))

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 post-accident sampling and analysis capability, consideration should be given to the following items:

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

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.

WNP-2 Position

The presently designed WNP-2 sampling system has been reviewed for adequacy with respect to post-accident sampling. A consultant has been contracted to review the system and make recommendations for redesign.

Based upon the Supply System's own investigations and the recommendations of the consultant, the WNP-2 architect/engineer will be directed to implement design changes as required. These changes will allow WNP-2 to adequately conduct post-accident sampling.

The design details of the system will be available for NRC review prior to April 1982.

II.B.4 TRAINING FOR MITIGATING CORE DAMAGE

Position (NUREG-0737)

Licensees are required to develop a training program to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severly damaged. They must then implement the training program.

Clarification

Shift technical advisors and operating personnel from the plant manager through the operations chain to the licensed operators shall receive all the training indicated in Enclosure 3 to H. R. Denton's March 28, 1980 letter.

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

WNP-2 Position

A training program covering the intent of the above position will be developed prior July 1982.

Training of operating personnel responsible for monitoring and controlling the reactor under degraded core conditions will be completed prior to operation of the reactor in a mode that could result in release of significant fission products as a result of core damage.

II.D.1 RELIEF AND SAFETY VALVE TEST REQUIREMENTS

Position

Describe a test program and schedule for testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

This requirement shall be met before fuel loading. See NUREG-0578, Section 2.1.2 (Reference 4), and letters of September 27 (Reference 23) and November 9, 1979 (Reference 24).

Clarification

Complete tests to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

This requirement shall be met by July 1, 1981. See NUREG-0578, Section 2.1.2 (Reference 4), and letters of September 27 (Reference 23) and November 9, 1979 (Reference 24)

WNP-2 Position

WNP-2 is a partcipant in the BWR Owners' Group which is addressing this task. The final test program description and results will be submitted to NRR by October 1, 1981.

II.D.3 RELIEF AND SAFETY VALVE POSITION INDICATION

Position

Reactor coolant system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe (NUREG-0737).

Clarification

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

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

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

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

e. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift).

WNP-2 Position

WNP-2 concurs with the intent of the NRC staff position requiring direct indication of the position of the main steam line safety/relief valves (SRV).

The Supply System will install acoustical monitors to measure the SRV operation. The acoustical monitors will provide qualitative flow and open/closed information for each safety/relief valve.

WNP-2 will be supplied with a single channel of acoustic instrumentation. The equipment will be seismically and environmentally qualified to Class 1 requirements.

Additional documentation will be available for NRC staff review ~~no later than four months~~ prior to November 12, 1981.

II.E.4.1 Dedicated Hydrogen Penetrations

Position

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

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

Clarification

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

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

c. Components furnished to satisfy this requirement shall be safety-grade.

d. Licensees that rely on purge systems as the primary means for controlling combustible gases following a loss-of-coolant accident should be aware of the positions taken in SECY-80-399, "Proposed Interim Amendments to 10 CFR Part 50 Related to Hydrogen Control and Certain Degraded Core Considerations." This proposed rule, published in the Federal Register on October 2, 1980, would require plants that do not now have recombiners to have the capacity to install external recombiners by January 1, 1982. (Installed internal recombiners are an acceptable alternative to the above.)

e. Containment atmosphere dilution (CAD) systems are considered to be purge systems for the purpose of implementing the requirements of this TMI Task Action item (NUREG-0737).

WNP-2 Position

WNP-2 has permanently installed redundant single failure proof post-LOCA hydrogen recombiners as described in FSAR 6.2.5. Dedicated containment penetrations are provided that meet the requirements of General Design Criteria 54 and 56 of Appendix A to 10CFR50. (Reference FSAR 3.1.2.5.5, 3.1.2.5.7, 6.2.4.1.1, 6.2.4.3.2.2.3.1, and Figures 3.2-17 and 6.2-31g.)

The dedicated containment penetrations are sized to satisfy hyrogen recombiner flow requirements based on Regulatory Guide 1.7 (Revision 1, dated September 1976) and 10CFR50.44 requirements.

No further WNP-2 action is required to comply with the intent of this task.

II.E.4.2 Containment Isolation Dependability

Position

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

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

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

d. The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic re-opening of containment isolation valves. Re-opening of containment isolation valves shall require deliberate operator action.

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

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

g. Containnment purge and vent isolation valves must close on a high radiation signal (NUREG-0737).

<u>Clarification</u>

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

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

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

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

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

f. The containment pressure history during normal operation should be used as a basis for arriving at an appropriate minimum pressure setpoint for initiating containment isolation. The pressure setpoint selected should be far enough above the maximum observed (or expected) pressure inside containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or

fluctuations due to the accuracy of the pressure sensor. A margin of 1 psi above the maximum expected containment pressure should be adequate to accouunt for instrument error. Any proposed values greater than 1 psi will require detailed justification. Applicants for an operating license and operating plant licensees that have operated less than one year should use pressure history data from similar plants that have operated more than one year, if possible, to arrive at a minimum containment setpoint pressure.

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

WNP-2 Position

For WNP-2, reactor water level (signals L, A, and V) and high drywell pressure (signal F) are used as diverse parameters indicative of a LOCA for initiation of containment isolation. In addition, high radiation measured in the Reactor Building ventilation exhaust plenum (signal Z) and in the main steam tunnel (signal C), as well as various high flow and room temperature signals indicative of line breaks outside containment are used selectively for system isolation, as indicated in Table II.E.4.2-1. Tabel II.E.4.2-2 provides a description of isolation signals identified in Table II.E.4.2-1.

Systems penetrating containment were reviewed on a functional basis to determine whether they are, or may be required to function following an accident to provide a safety-related response to the accident. Systems penetrating containment which are not required to perform a safety function at any stage of the response to the accident, between initiating event and cold shutdown, are considered "non-essential". Systems penetrating containment which may be called upon to perform a safety function, at any stage of the response to the accident, are considered "essential". Using these definitions (which differ from those used in NUREG-0578, but which are consistent with Appendix A to Branch Technical Position APCSB 3-1 and with standard usage), paths through containment are listed and categorized as essential or non-essential in Table

II.E.4.2-1 lines through containment for essential systems, which may be needed for long-term response to an accident, but not short-term (i.e., within 10 minutes), and would therefore be categorized "non-essential" per NUREG-0578, are indicated in Table II.E.4.2-1 by an asterisk (E*).

Table II.E.4.2-1 does not list systems for which all containment isolation valves are check valves, relief valves, locked closed, or manual only, since the purpose of the review of essential and non-essential systems is, ultimately, to identify any required logic changes or signal changes for automatic valves.

Following identification of essential and non-essential systems, non-essential systems were reviewed to assess whether diverse parameters are used as signals to close the isolation valves.

Except as indicated below, containment isolation valves in non-essential systems were found to use diverse parameters as isolation signals.

Exceptions:

a. Main steam, main steam drain lines and reactor water sample (RRC) line isolate on low reactor water level (signal A). If low water level failed to initiate isolation valve closure, and fuel failure resulted from the LOCA, Signal C, high radiation in the main steam tunnel, would close the isolation valves. In addition, signals indicative of a break in the main steam lines, as indicated in Table II.E.4.2-1, would initiate isolation valve closure.

b. The reactor water cleanup (RWCU) suction line valves isolate on low reactor water level (signal A). In addition, signals indicative of a break in the RWCU system would initiate isolation valve closure. High drywell pressure is not used as an isolation signal because it is desirable to operate the RWCU system under normal shutdown procedures, when high drywell pressure results from small steam leaks, small-break LOCAs, or failure of drywell coolers.

c. Normally closed containment isolation valves in non-essential systems do not, in some cases, use diverse parameters as isolation signals, as indicated in Table II.E.4.2-1. The requirement for diverse parameters as isolation signals is not

considered to apply when the isolation valves are normally closed and under Administrative Control.

The exceptions listed above are considered acceptable. As a result of this review for diverse parameters, no design changes were found to be necessary for containment isolation.

An investigation reviewing the logic for the containment isolation valves to verify that resetting the isolation signal would not result in the automatic re-opening of the containment isolation valve has been completed. Valves RRC-V-19 and 20, EDR-V-19 and 20 and FDR-V-3 and 4 were identified as being in violation of this requirement and have been corrected.

For addtional informaton, refer to FSAR Table 6.2-16, and FSAR Figures 6.2-31a through 31t.

WNP-2 is a participant in the BWR Owners' Group. The position taken by the Owners' Group and endorsed by WNP-2 with respect to containment setpoint pressure is as follows:

The containment isolation analytical setpoint pressure for Mark II containments is approximately 2 psig (drywell pressure). Under normal operating conditions, fluctuations in the atmospheric barometric pressure as well as heat inputs from such sources as pumps can result in containment pressure increases on the order of 1 psi. Consequently, the isolation setpoint of 2 psig provides a 1 psi margin above the maximum expected operating pressure. The 1 psi margin to isolation has proved to be a suitable value to minimize the possibility of spurious containment isolation. At the same time, it is such a low value (particularly in view of the small drywell volume of Mark II containments) that it provides a very sensitive and positive means of detecting and protecting against breaks and leaks in the reactor coolant system. No change of the setpoint is necessary for these containment types.

The WNP-2 containment purge valves satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 and the Staff Interim Position of October 23, 1979. See FSAR 6.2.1.1.8 and 6.2.4 for a description of the WNP-2 containment purge valves.

TABLE II.E.4.2-1

SYSTEM	INBOARD ISOLATION VALVE	OUTBOARD ISOLATION VALVE	CLASS.	ISOLATION SIGNALS LOCA	ISOLATION SIGNALS SYSTEM	COMMENTS
MAIN STEAM						
- main steam lines	MS-V-22A,B,C,D	MS-V-28A,B,C,D MS-V-67A,B,C,D	NE	A	C,G,D,P	
- MSIV-leakage control	MS-V-22A,B,C,D	MSLC-V-3A,B,C,D	E	-		Leakage control for MSIV.
- MS line drain	MS-V-16	MS-V-19	NE	A	C,G,D,P	
RRC						
- hydraulic lines	-	HY-V-17,18, 19,20,A,B	NE	A,F		
- pump seal water	RRC-V-13A,B	RRC-V-16A,B	E			Valves must stay open to prevent reactor coolant loss through seals.
HPCS						
- to RPV	HPCS-V-5	HPCS-V-4	E			Essential safety system.
- suppression pool suction	-	HPCS-V-15	E			
- test line	-	HPCS-V-23	NE	F,A		
- minimum flow line	-	HPCS-V-12	E			
LPCS						
- to RPV	LPCS-V-6	LPCS-V-5	E			Essential safety system.
- suppression pool suction	-	LPCS-V-1	E			
- test line	-	LPCS-V-12	NE	F,V		
- minimum flow line	-	LPCS-FCV-11	E			

TABLE II.E.4.2-1 (Continued)

SYSTEM	INBOARD ISOLATION VALVE	OUTBOARD ISOLATION VALVE	CLASS.	ISOLATION SIGNALS LOCA	ISOLATION SIGNALS SYSTEM	COMMENTS
SLC	SLC-V-7	SLC-V-4A,B	E	-		Outboard isolation valves are normally closed explosive valves. Must be available as backup to CRD system.
RHR						
- LPCI to RPV	RHR-V-41A,B,C,	RHR-V-42A,B,C	E			Safety system.
- drywell spray	-	RHR-V-16A,B RHR-V-17A,B	E*			Valves are normally closed and under administrative control.
- wetwell spray	-	RHR-V-27A,B	E*	F,V		Can override isolation signals provided LPCI injection valve is closed.
- shutdown cooling return	RHR-V-50A,B RHR-V-123A,B	RHR-V-53A,B	E*	L	U,M,R	Valves are closed during operation at power and under administrative control.
- shutdown cooling suction	RHR-V-9	RHR-V-8	E*	L	U,M,R	Valves are closed during operation at power and under administrative control.
- suppression pool suction	-	RHR-V-4A,B,C	E			
- minimum flow line	-	RHR-FCV-64A,B,C	E			
- test line	-	RHR-V-24A,B,C	NE	F,V		
- heat exchange condition	-	RHR-V-11A,B	NE	F,V		Normaly closed, only open for hot standby.
- heat exchange vent	-	RHR-V-73A,B	NE			No isolation signals. Valve normally closed, only open for hot standby

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TABLE II.E.4.2-1 (Continued)

SYSTEM	INBOARD ISOLATION VALVE	OUTBOARD ISOLATION VALVE	CLASS.	ISOLATION SIGNALS LOCA	ISOLATION SIGNALS SYSTEM	COMMENTS
RHR (Cont.)						
- CAC drains	-	RHR-V-134A,B	E*			Normally closed, only open when H_2 recombiners are needed.
- condensate drain pots	-	RHR-V-124A,B RHR-V-125A,B	NE			Normally closed, only open for hot standby.
- head spray	RCIC-V-66	RHR-V-23	E	A	U,M,R	
RCIC						
- condensing mode steam supply	RCIC-V-63	RCIC-V-64	NE		K,X	Normally closed valve only open for hot standby. RCIC system necessary for core cooldown following isolation from turbine condenser and feedwater makeup.
- turbine steam supply	RCIC-V-63	RCIC-V-8	E	I,X		
- pump minimum flow	-	RCIC-V-19	E			
- turbine exhaust	-	RCIC-V-68	E			
- turbine exhaust vacuum breaker	-	RCIC-V-110 RCIC-V-113	E	N		
- vacuum pump discharge	-	RCIC-V-69	E			
- suppression pool suction	-	RCIC-V-31	E			
- head spray	RCIC-V-66	RCIC-V-13	E			
CAC	-	CAC-V-2,4,6 8,11,13,15,17				Valves normally closed during operation.
		CAC-FCV-1A,B 2A,B,3A,B,4A,B				Only opened if H_2 recombiners are needed.

TABLE II.E.4.2- (Continued)

SYSTEM	INBOARD ISOLATION VALVE	OUTBOARD ISOLATION VALVE	CLASS.	ISOLATION SIGNALS LOCA	ISOLATION SIGNALS SYSTEM	COMMENTS
CSP/CEP						
- reactor building to wetwell vacuum breakers		CSP-V-5,6,9	E			Valves normally closed open automatically to relieve negative pressure
- wetwell ventilation supply		CSP-V-3,4	NE	F,A	Z	
- wetwell ventilation exhaust		CEP-V-3A,B, 4A,B	NE	F,A	Z	
- drywell ventilation supply		CSP-V-1,2	NE	F,A	Z	
- drywell ventilation exhaust		CEP-V-1A,B 2A,B	NE	F,A	Z	
RCC						
- inlet		RCC-V-5 RCC-V-104	NE	F,A		
- outlet	RCC-V-40	RCC-V-21	NE	F,A		
FPC						
- suppression pool cleanup suction		FPC-V-153 FPC-V-154	NE	F,A		
- suppression pool cleanup return		FPC-V-156	NE	F,A		
RWCU						
- from reactor	RWCU-V-1	RWCU-V-4	NE	A	J,E,Y,W	Valve does not close on high drywell pressure signal, to permit RWCU operation under small-break LOCA, or small steam leak condition.

TABLE II.E.4.2-1 (Continued)

SYSTEM	INBOARD ISOLATION VALVE	OUTBOARD ISOLATION VALVE	CLASS.	ISOLATION SIGNALS LOCA	ISOLATION SIGNALS SYSTEM	COMMENTS
RWCU (Cont.)						
- return to RFW		RWCU-V-40	NE			Connect to RFW system upstream of RFW isolation valves.
EDR		EDR-V-19 EDR-V-20	NE	F,A		
FDR		FDR-V-3 FDR-V-4	NE	F,A		
CIA						
- to relief valve accumulators		CIA-V-20	E			Essential because system supports safety equipment.
- to ADS accumulators		CIA-V-30A,B	E			
CRD						
- insert			E			Provides a desireable reflood capability.
- withdrawal			E			
I&C						
- RRC sample	RRC-V-19	RRC-V-20	NE	A	C	
- TIP lines		C51J004	NE	L,F		Closed system with no direct interface with reactor containment atmosphere.
- radiation monitors		PI-VX-250, 251,253,256, 257,259	NE	A,F		

LEGEND: E - essential during short-term response (within 10 minutes)
NE - nonessential
E* - essential during long-term response (after 10 minutes)

TABLE II.E.4.2-2

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION SIGNAL CODES

Signal	
L*	Reactor vessel low water level (Trip 3) - (A scram occurs at this level also. This is the higher of the three low water level signals.)
A*	Reactor vessel low water level (Trip 2)
C*	High radiation - Main steam
D*	Line break - Main steamline (steamline routing area high space temperature or steam line high steam flow)
F*	High drywell pressure (core standby cooling systems are started.)
J*	Line break in cleanup system - high space temperature.
K*	Line break in RCIC system line to turbine (high RCIC pipe space temperature, high steam flow, or low steam line pressure or high turbine exhaust pressure).
M*	Line break in RHR shutdown piping (high suction flow)
P*	Low main steam line pressure at inlet turbine (RUN mode only.)
U	High reactor vessel pressure.
W	High temperature at outlet of cleanup system non-regenerative heat exchanger.
Y	Standby liquid control system actuated.
Z*	Reactor building ventilation exhaust plenum high radiation.
RM	Remote manual switch located in main control room.
G*	Low condenser vacuum.

TABLE II.E.4.2-2 (Continued)

Signal	
X*	"K" plus RHR/RCIC equipment are high temperature.
N*	High drywell pressure and low reactor pressure.
R*	RHR equipment area high temperature.
V*	Reactor vessel low water level (Trip 1)
E*	Reactor water cleanup system high differential flow.
*	These are the isolation functions of the primary containment and reactor vessel isolation system; other functions are given for information only.

II.F.1 ADDITIONAL ACCIDENT-MONITORING INSTRUMENTATION (NUREG-0737)

Position (Introduction to II.F.1.1 through II.F.1.6)

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

a. Noble gas effluent radiological monitor:

b. Provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities (this requirement was inadvertently omitted from NUREG-0660; see II.F.1.2 that follows, for position);

c. Containment high-range radiation monitor;

d. Containment pressure monitor;

e. Containment water level monitor; and

f. Containment hydrogen concenration monitor.

NUREG-0578 provided the basic requirements associated with items (a) through (c) above. Letters issued to all operating nuclear power plants dated September 13, 1979 and October 30, 1979 provided clarification of staff requirements associated with items (a) through (f) above. II.F.1.1 through II.F.1.6 present the NRC position on these matters.

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

II.F.1.1 Noble Gas Effluent Monitor

Position

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

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

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

Clarification

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

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

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

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

The design description shall include the following information:

1. System description, including:

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

(ii) monitoring locations (or points of sampling), including description of methods used to assure representative measurements and background correction;

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

(iv) assurance of the capability to obtain readings at least every 15 minutes during and following an accident; and,

(v) the source of power to be used.

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

<u>WNP-2 Position</u>

WNP-2 is in the process of having extended range noble gas effluent monitors installed. Instrument ranges will be 10^{-6} to 10^{3} μCi/cc for the radwaste and turbine generator building and 10^{-5} to 10^{4} μCi/cc for the reactor building (Xe-133 equivalent). The power supplies will be from uninterruptible power.

Each elevated release duct, turbine building exhaust, and radwaste building exhaust is monitored for radioactive effluent gases by off-line systems. In addition, the elevated release duct has an in-line monitoring system.

The off-line systems draw samples from each exhaust duct through isokinetic probes. The sample passes through particulate and charcoal filters, a sample flow control system, and a radioactive gas monitor and is returned to the original exhaust duct. The sample flow rate is automatically adjusted to compensate for effluent flow changes. The system is equipped with local flow rate indication and remote flow rate trouble alarms to the control room. Each monitoring system has two separate detectors and instrument loops. (See Figures 11.5-5 and 11.5-6.) The ranges of these detectors are:

a. low range (10^{-6} μCi/cc to 10^{-1} μCi/cc Xe-133)

b. medium range (10^{-2} μCi/cc to 10^{3} μCi/cc Xe-133)

The detectors are set in lead shielding to reduce the unwanted background. The low-range detector is a beta-sensitive scintillator. The medium-range detector is a beta scintillator which measures the beta radiation in the sample chamber.

The in-line monitor provides high-range detection of six decades up to 10^{5} μCi/cc Xe-133. This is a pair of ion chambers set into the elevated release duct. Each instrument loop contains a detector (ion chamber) a power supply, a ratemeter, alarm modules, and a recorder. (See Figure 11.5-10.)

The low-range channel is equipped with a radioactive test source while the medium-range channel has a built-in electronic test circuit.

(Also, see 11.5.2.2.1.5, 11.5.2.2.1.6, 11.5.2.2.1.7, 11.5.2.2.3.2, and Table 11.5-1.)

TABLE II.F.1-1

HIGH-RANGE NOBLE GAS EFFLUENT MONITORS

REQUIREMENT - Capability to detect and measure concentrations of noble gas fission products in plant gaseous effluents during and following an accident. All potential accident release paths shall be monitored.

PURPOSE - To provide the plant operator and emergency planning agencies with information on plant releases of noble gases during and following an accident.

DESIGN BASIS MAXIMUM RANGE

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

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

- Undiluted PWR condenser air removal system exhaust.

10^4 μCi/cc - Diluted containment exhaust gases (e.g., >10:1 dilution, as with auxiliary building exhaust air).

- BWR reactor building (secondary containment) exhaust air.

- PWR secondary containment exhaust air.

10^3 μCi/cc - Buildings with systems containing primary coolant or primary coolant offgases (e.g., PWR auxiliary buildings, BWR, turbine buildings).

- PWR steam safety valve discharge, atmospheric steam dump valve discharge.

TABLE II.F.1-1 (Continued)

10^2 μCi/cc	-	Other release points (e.g., radwaste buildings, fuel handling/storage buildings).
REDUNDANCY	-	Not required; monitoring the final release point of several discharge inputs is acceptable
SPECIFICATIONS	-	(None) Sampling design criteria per ANSI N13.1
POWER SUPPLY	-	Vital instrument bus or dependable backup power supply to normal ac.
CALIBRATION	-	Calibrate monitors using gamma detectors to Xe-133 equivalent (1 R/hr @ 1 ft = 6.7 Ci Xe-133 equivalent for point source). Calibrate monitors using beta detectors to Sr-90 or similar long-lived beta isotope of at least 0.2 MeV.
DISPLAY	-	Continuous and recording as equivalent Xe-133 concentrations or μCi/cc of actual noble gases.
QUALIFICATION		The instruments shall provide sufficiently accurate responses to perform the intended function in the environment to which they will be exposed during accidents.
DESIGN CONSIDERATIONS	-	Offline monitoring is acceptable for all ranges of noble gas concentrations. Inline (induct) sensors are acceptable for 10^2 μCi/cc, offline monitoring is recommended. Upsteam filtration (prefiltering to remove radioactive iodines and particulates) is not required; however, design should consider all alternatives with respect to capability to monitor effluents following an accident. For external mounted monitors (e.g., PWR main steam line), the thickness of the pipe should be taken into account in accounting for low-energy gamma radiation.

II.F.1.2 Sampling and Analysis of Plant Effluents

Position

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

Clarification

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

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

c. The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities which are approximately isokinetic (same volocity) with expected induct or instack air velocities. For accident conditions, sampling may be complicated by a reduction in stack or vent effluent velocities to below design levels, making it necessary to substantially reduce sampler intake flow rates to achieve the isokinetic condition. Reductions in air flow may well be beyond the capability of available sampler flow controllers to maintain isokinetic conditions; therefore, the staff will

accept flow control devices which have the capability of maintaining isokinetic conditions with variations in stack or duct design flow velocity of ± 20%. Further departure from the isokinetic condition need not be considered in design. Corrections for non-isokinetic sampling conditions, as provided in Appendix C of ANSI 13.1-1969, may be considered on an ad hoc basis.

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

WNP-2 Position

A shielded low flow particulate/iodine sampling system is being installed to monitor the post-accident effluent air from the reactor building ventilation exhaust. The sample system consists of a shielded filter holder, a running time meter, and a low volume positive displacement sample pump which draws a sample from the reactor building elevated release duct. The sample is drawn through the particulate and iodine filter assembly at a rate of about 0.1 cfm and then returned to the release duct. The pump is automatically started when the high-high level alarm on the associated noble gas monitor is activated. The pump will continue to run until manually reset. The sample filter holder has a quick-release allowing it to be removed and handled with remote tools reducing any potential personnel exposure.

To protect personnel, a 2-inch thick lead shield is positioned around the filter holder. This will reduce the dose rate to 5 mR/hr at one foot from the filter under worst postulated conditions following a reactor accident based on Table II.F.1-2, Design Basis Shielding Envelope.

The shielded sample assembly will be used on the reactor building because of potential leakage from primary containment into the reactor building following a reactor accident releasing fission products from the core. Particulate/iodine sampling of the other buildings' (radwaste and turbine) exhausts will be handled by the normal effluent samplers where the post-accident release concentration is quite low.

If there were a reactor accident with a core fission product release, the reactor building (secondary containment) immediately isolates. It's atmosphere is maintained at a 0.25" H_2O vacuum by the standby gas treatment system (SGTS). The only potential airborne contamination that could reach the other builings is from the SGTS by-pass leakage as listed in Table 6.1-16 which totals 0.74 scfh of which 0.35 scfh is into the radwaste building. Assuming an iodine concentration of 3.7 X 10^4 μCi/cc (50% core inventory is released in the drywell atmosphere and 50% plates out) in the in-leakage air to the radwaste building, then the building exhaust (83,000 cfm) concentration will be 2.6 X 10^{-3} μCi/cc if the building volume dilution is ignored. The normal effluent sampler operates at 3 cfm; therefore, the charcoal cartridge 30 minute accumulation would be 6.7 mCi. This would result in a dose rate of 21 mR/hr at one foot from the cartridge. Doubling the dose rate to account for particulates yields 42 mR/hr at one foot from the sample assembly. Because of the high exhaust flow rate (260,000 cfm) and less in-leakage (0.24 scfh) the turbine building exhaust is less concentrated. Therefore, the radwaste and turbine building normal effluent sampling systems are considered adequate for post-accident sampling. (See 11.5.2.2.1.5 and Figure 11.5-5.)

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TABLE II.F.1-2

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

EQUIPMENT - Capability to collect and analyze or measure representative samples of radioactive iodines and particulates in plant gaseous effluents during and following an accident. The capability to sample and analyze for radioiodine and particulate effluents is not required for PWR secondary main steam safety valve and dump valve discharge lines.

PURPOSE - To determine quantitative release of radioiodines and particulates for dose calculation and assessment.

DESIGN BASIS SHIELDING ENVELOPE - 10^2 μCi/cc of gaseous radioiodine and particulates, deposited on sampling media; 30 minutes sampling time, average gamma energy (E) of 0.5 MeV.

SAMPLING MEDIA

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

SAMPLING CONSIDERATIONS

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

ANALYSIS

- Design of analytical facilities and preparation of analytical procedurs shall consider the design basis sample.

TABLE II.F.1-2 (Continued)

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

II.F.1.3 Containment High-Range Radiation Monitor

Position

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

Clarification

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

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 post-accident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gammas and are not acceptable.

WNP-2 Position

WNP-2 concurs with the intent of this task and is in the process of having high range radiation monitors installed in primary containment. The monitors will be redundant, seismically and environmentally qualified to Class I requirements and will operate in a design basis accident environment. The monitors will have a range of 1 R/hr to 10^7 R/hr. The complete design description will be provided prior to April 1982.

TABLE II.F.1-3

CONTAINMENT HIGH-RANGE RADIATION MONITOR

REQUIREMENT	-	The capability to detect and measure the radiation level within the reactor containment during and following an accident.
RANGE	-	1 rad/hr to 10^8 rads/hr (beta and gamma) or alternatively 1 R/hr to 10^7 R/hr (gamma only).
RESPONSE	-	60 keV to 3 MeV photons, with linear energy response ± 20%) for photons of 0.1 MeV to 3 MeV. Instruments must be accurate enough to provide usable information.
REDUNDANT	-	A minimum of two physically separated monitors (i.e., monitoring widely separated spaces within containment).
DESIGN AND QUALIFICATION	-	Category 1 instruments as described in Appendix A, 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.

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

WNP-2 Position

WNP-2 concurs with the intent of this task and is in the process of modifying the primary containment pressure instrumentation. Once modified the redundant instruments will have a range of 12 psia to 180 psig per Regulatory Guide 1.97, and will be seismically and environmentally qualified to Class 1 requirements. Continuous recording will be available in the control room. The complete design description will be provided prior to January 1982.

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 gallon capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

Clarification

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

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

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

WNP-2 Position

WNP-2 concurs with the intent of this task and is in the process of having the suppression chamber water level instrumen-

tation modified. Once modified the instruments will be seismically and environmentally qualified to Class 1 requirements, redundant, with readout in the control room. Instrument range will be from the center line of the HPCS suction line to 5 ft. above normal water level. The complete design description will be provided prior to January 1982.

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.

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

WNP-2 Position

WNP-2 concurs with the intent of this position. The existing monitors are redundant providing 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. Complete design description will be provided prior to January 1982.

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

WNP-2 Position

WNP-2 concurs with the intent of this task and is implementing a design study to supplement the existing reactor vessel water level instrumentation. The design study is considering installation of additional, redundant channels of water level indication. The indication will extend from below the active core to just below the vessel head flange. Per NUREG-0737, a complete design description will be forwarded for review to the NRC prior to January 2, 1982.

II.K.1.5 Assurance of Proper ESF Functioning

Position

Review all valve positions, positioning requirements, positive controls and related test and maintenance procedures to assure proper 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.

Clarification

None

WNP-2 Position

Directives on valve positioning requirements, positive controls, and test and maintenance procedures associated with ESF systems are being prepared. Motor-operated valves in safety systems will normally be maintained in a configuration such as to require the least number of valve automatic movements upon 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 and documentation of locks on valve handwheels. In addition, numerous vital manual valves have position status indicating lights in the WNP-2 Control Room.

WNP-2 will be 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 inlcude:

- a. Valve position
- b. Power available to motor-operated valves
- c. Initiation logic power available
- d. Power sources (including emergency diesels) available
- 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 upon completion of testing.

When ESF equipment is removed from service for maintenance, WNP-2 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.

II.K.1.10 Safety-Related System Operability Status Assurance

Position

Review and modify, as required, procedures for removing safety-related systems from service and (restoring to service) to assure operability status is known. See Bulletins 79-05A Item 10, 79-06A Item 10, 79-06B Item 9, and 79-08 Item 8.

This requirement shall be met before fuel loading.

Clarification

None

WNP-2 Position

Refer to the responses for Items II.K.1.5 and I.C.6 for compliance with the intent of this position.

In addition, all safety-related systems removed from service (and restored) will be recorded in appropriate plant logs and on applicable equipment status boards.

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

WNP-Position

WNP-2 letter G02-80-107 of May 23, 1980, responding to IE Bulletin 79-08, provided the following:

The auxiliary heat removal systems provided to remove decay heat from the reactor core and containment following loss of the feedwater systems are:

- High Pressure Core Spray System (HPCS)
- Reactor Core Isolation Cooling (RCIC) System
- Low Pressure Core Spray System (LPCS)
- RHR System - LPCI Mode
- RHR System - Suppression Pool Spray Mode
- RHR System - Suppression Pool Cooling Mode
- Residual Heat Removal (RHR/Low Pressure Coolant Injection (LPCI) System

The description that follows details the operation of the systems needed to achieve initial core cooling followed by containment cooling and then followed by extended core cooling for long-term plant shutdown, assuming the reactor is scrammed and isolated from the main condenser.

Initial Core Cooling:

Following a loss of feedwatr 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 automaticaly reopen when reactor water level decreases to low water level 2. The RCIC System must be manually reset by the operator in the control room before it will automatically re-initiate after a high water level 8 trip.

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

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.

c. Verifying system flow is to the reactor by checking control room position indication of motor-operated valves. This assures 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 Low Pressure Core Spray (LPCS) or Low Pressure Coolant Injection (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 safety/relief valve (SRV) discharge to the suppression pool. This would be accomplished by placing the Residual Heat Removal (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.

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

a. Verifying RHR and Service Water (SW) system flow usinng system control room flow indicators.

b. Verifying correct RHR and SW system flow paths using control room position indication of motor-operated valves.

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 ~~Drilling:~~ 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 coling 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 WNP-2 plant design is fully adequate to meet the intent of the requirements of auxiliary heat removal when the main feedwater 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

WNP-2 Position

NEDO-24708 describes the multiple water level instrumentation provided in the BWR control room for the operator. An outline of the specific indication for WNP-2 is provided in the following paragraphs, which fully meets the intent of the plant requirements and the NRC requirements.

Reactor vessel water level in the WNP-2 BWR is continuously monitored by eleven (11) indicators or recorders for normal, transient and accident conditions. In general, those monitors used to provide manual safety equipment initiation are arranged in a redundant array with two instruments, one in each of two independent electrical divisions. 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 procedurs will reflect the requirements for the operators to also rely upon the information provided by other plant parameter indications relating to vessel level.

The range of reactor vessel water level from below the top of the active fuel area up to the top of the vessel is covered by a combination of narrow and wide-range instruments. Level is indicated and/or recorded in the control room.

A separate set (to that described above) of narrow-range and wide-range level instrumentation on separate condensing chambers provides reactor level control via the reactor feedwater system. This set also indicates or records in the control room (three narrow-range level indicators and one wide-range level recorder).

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

- Reactor Core Isolation Coolant System (RCIC)
- High Pressure Core Spray System (HPCS)
- Low Pressure Core Spray System (LPCS)
- Residual Heat Removal/Low Pressure Coolant Injection (RHR/LPCI)
- Automatic Depressurization System (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 Non-essential Loads

The modifications resulting from TMI Task II.F.2 will change the number of level detectors but will not change the intent of the response to the task. Upon completion of the modifications for NUREG Task II.F.2 this response will be updated to reflect the changes due to II.F.2.

Low reactor vessel water level is used in the initiation logic of all systems listed above. In addition, the RCIC and HPCS systems shutdown on high reactor vessel water level. HPCS will automatically restart if low reactor level is again reached. (See response to TMI Item II.K.1.22 for further discussion.) In the case of RCIC, manual resetting is required if high reactor vessel water level is reached.

II.K.3.3 Failure of PORV or Safety Valve to Close

<u>Position</u>

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report.

This requirement shall be met before issuance of a full power license (NUREG-0694).

<u>Clarification</u>

None

<u>WNP-2 Position</u>

Administrative procedures will be prepared to meet the intent of the above and implemented at WNP-2 prior to July 1982. The procedures will be available onsite for NRC I&E review.

II.K.3.13 Separation of HPCI and RCIC System Initiation Levels

a. Analysis
b. Modify

Position

Currently, the reactor core isolation cooling (RCIC) system and the high pressure coolant injection (HPCI) system both initiate on the same low water level signal and both isolate on the same high water level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low-flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC systems should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the RCIC system, initiation logic should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analyses should be submitted to the NRC staff and changes should be implemented if justified by the analyses (NUREG-0737).

a. Documentation provided results of evaluation and proposed modifications (if necessary) to staff by October 1, 1980. Provide sufficient supporting analysis to demonstrate that the systems, as modified, would not degrade proper system functions.

b. Modifications shall be completed (if necessary) by April 1, 1981.

See letter September 5, 1980, Enclosure 2, pg. 7 (Reference 33).

Clarification

None

WNP-2 Position

At WNP-2 the HPCS and RCIC are both initiated a low-water level 2 (477.5 inches above vessel zero).

As a generic item, the possible separation of initiation levels for RCIC and HPCS was studied by GE for the BWR Owners' Group. The results of that study were provided to the

Commission in a GE letter of October 1, 1980 from R. A. Buchholz to D. G. Eisenhut. The conclusions of that study are endorsed by WNP-2, specifically, that the proposed separation of RCIC and HPCS initiation is unnecessary. The basis is that for rapid level changes associated with accident scenarios and severe transients their initiation would be essentially simultaneous in that possible separation distances could not preclude HPCS challenges; likewise, for slow level changes due to small leaks or slow transients, adequate time exists for manual initiation of RCIC by the reactor operator, prior to HPCS auto-initiation. Justification of this basis is that over the lifetime of a unit, the expected occurrence of slow level decreases does not warrant installation of equipment changes to decrease the number of challenges made to the HPCS. Manual operator response to maintain water level is consistent with abnormal operations demands.

GE and the BWR Owners' Group have submitted an analysis of the RCIC system for automatic reset following a high water level trip. The Owners' Group has recommended automatic closure of the steam supply valve on high vessel water level with the RCIC turbine trip valve remaining open. This leaves the system in a standby mode capable of restarting at low water level. Very little modification of existing circuitry is required to effect this change. WNP-2 endorses the Owners' Group position and will make the necessary equipment modifications. Changed circuit and logic diagrams for these changes will be available for review by November 12, 1981.

II.K.3.15 Modify Break-Detection Logic to Prevent Spurious Isolation of High Pressure Coolant Injection and Reactor Core Isolation Cooling

Position

The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe break detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe break detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause inadvertent system isolation (NUREG-0737).

Clarification

None

WNP-2 Position

WNP-2 does not have a steam-driven HPCI system, but instead has a motor-driven HPCS system for which this modification does not apply. However, WNP-2 concurs with the intent of this position for the RCIC and will modify the RCIC pipe break detection circuitry to add a time delayed inhibit to the isolation signals. This minor change will eliminate the potential for isolation of the RCIC system due to the pressure spike caused by system startup.

A description of the modification as installed will be provided prior to November 12, 1981.

II.K.3.16 Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification

Position

The record of relief valve failures to close for all boiling water reactors (BWRs) in the past 3 years of plant operation is approximately 30 in 73 reactor-years (0.41 failures per reactor-year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small-break loss-of-coolant accident (LOCA). The high failure rate is the result of a high relief valve challenge rate and a relatively high failure rate per challenge (0.16 failures per challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

a. Additional anticipatory scram on loss of feedwater,

b. Revised relief valve actuation setpoints,

c. Increased emergency core cooling (ECC) flow,

d. Lower operating pressures,

e. Earlier initiation of ECC systems,

f. Heat removal through emergency condensers,

g. Offset valve setpoints to open fewer valves per challenge,

h. Installation of additional relief valves with a block or isolation valve feature to eliminate opening of the safety/relief valves (SRVs), consistent with the ASME Code,

i. Increasing the high steam line flow setpoint for main steam line isolation valve (MSIV) closure,

j. Lowering the pressure setpoint for MSIV closure,

k. Reducing the testing frequency of the MSIVs,

l. More stringent valve leakage criteria, and

m. Early removal of leaking valves.

An investigatin of the feasibility and contra-indications of reducing challenges to the relief valves by use of the aforementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

Clarification

Failure of the power-operated relief valve (PORV) to reclose during the TMI-2 accident resulted in damage to the reactor core. As a consequence, relief valves in all plants, including BWRs, are being examined with a view toward their possible role in a small-break LOCA.

The safety/relief valves (SRV) are dual-function pilot-operated relief valves that use a spring-actuated pilot for the safety function and an external air-diaphragm-actuated pilot for the relief function.

The operating history of the SRV has been poor. A new design is used in some plants but the operational history is too brief to evaluate the effectiveness of the new design. Another way of improving the performance of the valves is to reduce the number of challenges to the valves. This may be done by the methods described above or by other means. The feasibility and contra-indications of reducing the number of challenges to the valves by the various methods should be studied. These changes which are shown to decrease the number of challenges without compromising the performance of the valves or other systems should be implemented.

The failure of an SRV to reclose will be the most probable cause of a small-break LOCA. Based on the above guidance and clarification, results of a detailed evaluation should be submitted to the staff. The licensee shall document the proposed system changes for staff approval before implementation.

WNP-2 Position

WNP-2 is a participant in the BWR Owners' Group and endorses the position prepared by General Electric and the Owners' Group. In summary this position shows that a significant reduction in relief valve challenges and failures is attained over industry history by the BWR five (5) design and installation of Crosby safety/relief valves instead of the three-stage Target Rack valves. WNP-2, as a BWR five (5) design with

Crosby relief valves, realizes approximately a factor of 12 reduction over industry history. Additionally, the position shows that further design modification will not substantially change the challenge and/or failure rate for the WNP-2, BWR five (5) Crosby SRV design.

This position was presented by GE to the NRC on behalf of the Owners' Group in letter from D. B. Waters to D. G. Eisenhut, dated March 31, 1981, "BWR Owners' Group Evaluation of NUREG-0737 Requirements Items II.K.3.16 and II.K.3.18."

II.K.3.17 Report on Outages of Emergency Core Cooling Systems Licensee Report and Proposed Technical Specification Changes

Position

Several components of the emergency core cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outage for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation) (NUREG-0737).

Clarification

The present technical specifications contain limits on allowable outage times for ECC systems and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECC equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with the quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) cause of the outage; (3) ECC systems or components involved in the outage; and (4) corrective action taken. Test and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicant for an operating license shall establish a plan to meet these requirements.

WNP-2 Position

The position statement by NRC required a report to be submitted by operating plants to identify actual ECCS outage

experience for the last five years of operation. The report requirement does not apply to WNP-2 since no operating experience is available. The Tech Specs for WNP-2 will be prepared and submitted for NRC review and approval based on currently acceptable ECCS outage times, by December 30, 1981.

II.K.3.18 Modification of Automatic Depressurization System Logic-Feasibility for Increased Diversity for Some Event Sequences

Position

The automatic depressurization system (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme that should be considered is ADS actuation on low reactor vessel water level provided no high pressure coolant injection (HPCI) or high pressure coolant system (HPCS) flow exists and a low pressure emergency core cooling (ECC) system is running. This logic would complement, not replace, the existing ADS actuation logic.

Clarification

None

WNP-2 Position

WNP-2 is a member of the BWR Owners' Group which has just recently completed the required feasibility and risk assessment study. The results of this study have been transmitted in a letter from GE to NRC, D. B. Waters to D. G. Eisenhut, dated March 31,1981. In this study, five ADS logic options, including retaining the current design, were considered. WNP-2 has evaluated these options and has concluded that the current ADS logic design, with implementation of the symptom-oriented emergency procedure guidelines (EPGs), is adequate. As pointed out in the Owners' Group study, the transients that are of concern are slow developing events, and with the incorporation of the EPGs the operator (under worst conditions) has 30 to 40 minutes in which to act. WNP-2 believes this provides the operator with sufficient time to evaluate the situation (using the EPGs) and take the necessary action.

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.

WNP-2 Position

WNP-2 as a participant in the BWR Owners' 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 Owners' 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. WNP-2 concurs in this position.

II.K.3.22 Automatic Switchover of Reactor Core Isolation Cooling System Suction-Verify Procedures and Modify Design

Position

The reactor core isolation cooling (RCIC) system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cognizant procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

Clarification

None

WNP-2 Position

WNP-2 committed to automatic RCIC suction transfer in response to WNP-2 docket Question 031.015. Per that commitment, WNP-2 is in the process of installing redundant, seismic and quality Class I level switches on the Seismic Class I RCIC suction piping. These switches will sense the loss of the condensate storage tank as a supply and switch the RCIC suction to the suppression pool automatically. Complete design description will be provided prior to November 12, 1981.

II.K.3.24 Confirm Adequacy of Space Cooling for High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems

Position

Long-term operation of the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) systems may require space cooling to maintain the pump room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of alternating-current power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite alternating-current power to their support systems, including coolers, for at least 2 hours.

Clarification

None

WNP-2 Position

WNP-2 provides an emergency space cooling system to those equipment rooms containing the HPCS and RCIC pumps. Each emergency space cooling system, is powered from a Class 1E bus and is designed to withstand the effects of a safe shutdown earthquake. Loss of offsite power will not affect the ability of the space coolers to operate. See FSAR 9.4.9 for a description of the capabilities of the Reactor Building Emergency Cooling system. The cooling water to the system is supplied from the standby service water system. Loss of offsite power will not affect the ability of the standby service water system to provide cooling water. See FSAR 9.2.7 and 6.2.2 for a description of the capabilities of the standby service water system.

In conclusion, loss of offsite alternating-current power will not cause adverse space cooling conditions for the RCIC and HPCS pump rooms.

No further WNP-2 action is required to comply with the intent of this task.

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 and anticipated operational occurrence. Loss of ac power for this case is construed to be loss of offsite power. If seal failure is the consequence of loss of cooling water to the reactor coolant pump (RCP) seal coolers for 2 hours, due to loss of offsite power, one acceptable solution would be to supply emergency power to the component cooling water pump. This topic is addressed for Babcock and Wilcox (B&W) reactors in Item II.K.2.16.

WNP-2 Position

WNP-2 as a participant in the BWR Owners' Group endorses the position developed by General Electric for the Owners' Group. This position shows that a total failure of the recirculation pump seal cooling systems, followed by extreme degradation of the pump seals results in a primary coolant loss of less than 70 gallons per minute.* 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 was presented to the NRC by General Electric.

*It should be noted that cooling can be provided to the seals via the seal purge system. This system is supplied water from the CRD pumps which are powered from emergency buses. Though the pumps are not part of automatic load sequence, they may be manually started and cooling water supplied to the seals as needed from the condensate system (Condensate Storage Tank).

II.K.3.27 Provide Common Reference Level for Vessel Level Instrumentation

Position

Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points (NUREG-0737).

Clarification

None

WNP-2 Position

WNP-2 complies with this position. However, the common reference water level used is "zeroed" at the normal operating water level as shown in FSAR Figure 5.3-2. Justification for using the normal water level is as follows. When system upset conditions occur and vessel level varies, the operator's primary focus is not how far above the top of the active fuel (TAF) the vessel level is, but how far above or below "normal" it is. The majority of transients will not be severe enough to make core coverage the major concern of the operator. To focus his attention by use of a common "zero" reference at TAF would detract from less severe system upsets and may increase the probability of escalating the upset condition. The water level references must allow the operator to accurately and quickly respond to both minor and severe system upsets.

Under various pressure and temperature conditions, the TAF indicated level will vary. Use of a "zero" reference on the fuel zone indicator is therefore not meaningful to the operator during transient conditions without pressure/temperature compensation curves, and may even falsely imply accuracy to the operator. Knowing how far ~~before~~ TAF level actually is does not influence the operator's action, only trend will influence his action. Thus use of a TAF reference "zero" is meaningless.

below

II.K.3.28 Verify Qualification of Accumulators on Automatic Depressurization System Valves

Position

Safety analysis reports claim that air or nitrogen accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated that the emergency core cooling (ECC) systems are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee must show that the accumulator design is still acceptable.

Clarification

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments and taking no credit for nonsafety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves.

WNP-2 Position

The ADS valves accumulators and associated equipment and instrumentation for WNP-2 are designed to withstand a hostile environment and perform their function for 100 days following an accident. The ADS nitrogen supply system was conservatively designed for 30 days operation following a LOCA (see FSAR 9.3.1.2). WNP-2 has modified the system so that nitrogen leakage from the system can be compensated for under any circumstances through a remote connection which is accessible outside the secondary containment (outside the railway air lock). A portable nitrogen supply can then be connected to augment the existing nitrogen supply.

This supplementary, portable nitrogen supply consists of two nitrogen bottle connections (one for each supply header to the ADS valves) located in the corridor between the reactor building and the diesel generator building. A supplementary nitrogen bottle is manually valved in to its supply header when a local counter indicates the last nitrogen bottle in the railway air lock has gone on service or when header pressure (indicated in the control room) begins to decrease.

II.K.3.30 Revised Small-Break Loss-of-Coolant Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K

Position

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities (NUREG-0737).

Clarification

As a result of the accident at TMI-2, the Bulletins and Orders Task Force was formed within the Office of Nuclear Reactor Regulator. This task force was charged, in part, to review the analytical predictions of feedwater transients and small-break LOCAs for the purpose of assuring the continued safe operation of all operating reactors, including a determination of acceptability of emergency guidelines for operators.

As a result of the task force reviews, a number of concerns were identified regarding the adequacy of certain features of small-break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each light-water reactor (LWR) vendor's models, were documented in the task force reports for each LWR vendor. In addition to the modeling concerns identified, the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small-break LOCA model as required by II.4 of Appendix K to 10CFR50 was needed. This included providing predictions of Semiscale Test S-07-10B, LOFT Test (L3-1), and providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small-break LOCAs.

Based on the cumulative staff requirements for additional small-break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

The purpose of the verification was to provide the necessary assurance that the small-break LOCA models were acceptable to calculate the behavior and consequences of small primary

system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small-break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.*

The specific staff concerns regarding small-break LOCA models are provided in the analysis sections of the B&O Task Force reports for each LWR vendor, (NUREG-0635, -0565, -0626, -0611, and -0623). These concerns should be reviewed in total by each holder of an approved emergency core cooling system (ECCS) model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small-break test series and LOFT Tests (L3-1) and L3-2). The staff believes that the present small-break LOCA models can be both qualitatively and quantitatively assessed against these tests. Other separatage effects test (e.g., ORNL core uncovery tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify (1) which areas of the models, if any, the licensee intends to upgrade, (2) which areas the licensee intends to address by further justification of acceptability, (3) test data to be used as part of the overall verification/upgrade effort, and (4) the estimated schedule for performing the necessary work and submitting this information for staff review and approval.

WNP-2 Position

The General Electric Company final response to this concern was provided in GE letter MFN-132-81, R.H. Buchholz (GE) to D.G. Eisenhult "NUREG-0737, Item II.K.3.30 - Final Program Results", dated June 26, 1981. The Supply System concurs with the results of the GE program that concludes no changes to the existing model are needed.

* As an example, a model that presently does not properly account for horizontal countercurrent two-phase flow in the hot leg piping should either be revised to properly account for the phenomenon, or demostrated to produce a conservative result for the entire spectrum of small breaks considered.

II.K.3.31 Plant-Specific Calculations to Show Compliance with 10 CFR Part 50.46

Position

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) as described in Item II.K.3.30 to show compliance with 10CFR50.46 should be submitted for NRC approval by all licensees (NUREG-0737).

Clarification

None

WNP-2 Position

The GE II.K.3.30 final response has been submitted, see response II.K.3.30. The plant specific analysis for WNP-2 has been completed and is reflected in a revision to 6.3.3.

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

WNP-2 Position

WNP-2 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 emergency core cooling system (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. In order to meet this requirement, eigher 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 <u>active</u> failure.

d. All plant systems and components are assumed to functon 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, FWCI, HPCS, RCIC or IC.

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

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 typicla 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.

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 fuunction 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 feet to 11 feet 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 LOF 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.

It is concluded that for anticipated transients combined with the worst single failure the core remains covered. Additionally, it is concluded that for severely degraded transients beyond the design basis where it is assumed that a SORV sticks open and an additional failure occurs the core remains covered with proper operator action.

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 - Decreasinng 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

THE WORST CASE OF TRANSIENT WITH A SINGLE FAILURE FOR DIFFERENT BWR PRODUCT LINES

Product Line	Transient with a Single Failure (The 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

NUREG-0737

This report applies to the following plants, whose owners participated in the report's development.

Boston Edison	Pilgrim 1
Caroline Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 1-3, Quad Cities 1 & 2
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Jersey Central Power & Light	Oyster Creek 1
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	Fitzpatrick
Tennessee Valley Authority	Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 & 2
Vermont Yankee Nuclear Power	Vermont Yankee
Detroit Edison	Enrico Fermi 2
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2

TABLE II.K.3.44-4 (Continued)

Washington Public Power Supply System	WNP-2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2
Long Island Lighting	Shoreham

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

WNP-2 Position

WNP-2 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:

a. No high pressure cooling systems are available.

b. All low pressure ECC systems are available.

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. Hoewever, 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 steamline 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 make-up 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).

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 steamline break. As the length of depressuriization 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' and Level 2 + 60 seconds) 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 steamline 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.

References:

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 STEAMLINE BREAK
NO HIGH PRESURE 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 (LBS)
FULL ADS	TAF*	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** + 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

*TOP OF ACTIVE FUEL

**HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE II.K.3.45-2

RESULTS FOR BWR/6 STUCK-OPEN RELIEF VALVE
NO HIGH PRESURE 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 (LBS)
FULL ADS	TAF*	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** + 60 Sec.	77.7	No Uncovery	1.961×10^5

*TOP OF ACTIVE FUEL

**HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE II.K.3.45-3

RESULTS FOR BWR/3 OUTSIDE STEAMLINE BREAK
NO HIGH PRESURE 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 (LBS)
FULL ADS	TAF*	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** + 60 Sec.	364.4	No Uncovery	2.446×10^5
CASE 1	Level 1 + 60 Sec.	364.4	10	2.394×10^5

*TOP OF ACTIVE FUEL

**HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE II.K.3.45-4

RESULTS FOR BWR/3 OUTSIDE STEAMLINE BREAK
ON APPENDIX K ASSUMPTIONS WITH NO HIGH PRESSURE SYSTEMS

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 (LBS)
FULL ADS	TAF*	759.4	264	1.960×10^5
CASE 1	TAF	759.4	277	1.913×10^5
FULL ADS	Level 1** + 60 Sec.	145.6	175	2.210×10^5
CASE 1	Level 1 + 60 Sec.	145.6	191	2.165×10^5

*TOP OF ACTIVE FUEL

**HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE II.K.3.45-5

NUREG-0737

This report applies to the following plants, whose owners participated in the report's development.

Boston Edison	Pilgrim 1
Caroline Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 2 & 3, Quad Cities 1 & 2
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Jersey Central Power & Light	Oyster Creek 1
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Northern States Power	Monticello
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	Fitzpatrick
Tennessee Valley Authority	Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 & 2
Vermont Yankee Nuclear Power	Vermont Yankee
Detroit Edison	Enrico Fermi 2
Long Island Lighting	Shoreham
Mississippi Power & Light	Grand Gulf 1 & 2

TABLE II.K.3.45-5 (Continued)

Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	WNP-2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2

Slip Sheet

for

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(Figure II.K.3.45-1)

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

WNP-2 Position

GE, acting for the BWR Owners' Group, responded 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.

III.A.1.1 Upgrade Emergency Preparedness

Position

Provide an emergency response plan in substantial compliance with NUREG-0654, "Criteria for preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (which may be modified after May 13, 1980 based on public comments) except that only a description of a completion schedule for the means for providing prompt notification to the population (Appendix 3), the staffing for emergencies in acdition to that already required (Table B.1), and an upgraded meteorological program (Appendix 2) need be provided. NRC will give substantial weight to FEMA findings on offsite plans in judging the adequacy against NUREG-0654. Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations (NUREG-0694).

Clarification

None

WNP-2 Position

The Washington Public Power Supply System WNP-1, -2, -4 Hanford Site Emergency Plan was submitted to the NRC in March 1981. The Emergncy Plan complies with the intent of 10 CFR 50.47, 10 CFR 50.54, and Appendix E. The Emergency Plan commplies with the intent of the essential elements of NUREG-0654 but does not comply with Regulatory Guide 1.101 as this guide was withdrawn per Federal Register Notice, Tuesday, October 21, 1980.

An exercise to demonstrate the capabilities of the Supply System's Emergency Preparedness Program will be ~~held prior to July 1982~~ Conducted. The exercise will utilize a temporary Emergency Operations Facility to test the integrated capability of the Emergency Preparedness plans and organizations if the permanent facilities are not available.

available in the TSC and EOF on a near real time basis prior to fuel loading with the capability for remote interrogation. In addition, these parameters are available as input to the Supply System emergency dose projection system for the purpose of the prefuel load exercise.

A backup meteorological measurements system will be designated prior to fuel loading. The backup meteorological measurements system will be capable of being accessed at the EOF, TSC, and control room, and will be remotely interrogable.

A Class A meteorological model and dose assessment capability (Reference Appendix 2, NUREG-0654) is available for use as part of the emergency dose projection system. The system is capable of producing initial transport, diffusion, and dose estimates within the plume exposure EPZ within 15 minutes following the classification of an accident. An emergency dose calculation manual describing the meteorological model and use of the system, including a methodology for projecting doses out to the plume exposure pathway EPZ, is available to the NRC and copies will be placed in appropriate emergency response facilities prior to the prefuel load exercise.

An ongoing study is being conducted by the Supply System to evaluate the impact of seasonal, diurnal, and terrain-induced flows on the meteorological model. The emergency dose projection system display, which utilizes colorgraphic video output of the site grid map and areas of projected radiological hazard, and/or extensive tabular data concerning projected doses and field sampling can be rapidly telecopied to the NRC and other emergency response organizations. This is a desirable method for transmission of this data due to time limitations encountered in sending a digitized map and a voluminous amount of data via a 1200 baud data transmission link. Current estimates of the time required to transmit the video display output run about five to ten minutes per display as opposed to about 20 seconds for the same data to be telefaxed.

The facsimile method would minimize operator cross training and computer compatibility problems associated with an on-line computer link and would be more reliable in an emergency situation. This method would also alleviate possible assessment delays caused by loading the dose assessment computer with multiple interrogations during an emergency when time may be critical.

All "real time" meteorological and source data which serves as input to the emergency dose projection system will be available via a conventional data link capability to permit independent verification of dose calculations. The selection of a more comprehensive meteorological model incorporating advanced temporal and spatial aspects (sometimes referred to as "Class B" meteorology) is being developed by the Supply System. Final model design and implementation scheduling await the issuance of guidelines by the NRC. The models used by all emergency response facilities will be evaluated for compatibility.

d. Emergency Staffing

The operating crew for each eight-hour shift at the plants normally consists of a shift manager, control room supervisor, shift support supervisor, licensed reactor operators, equipment operators, shift technical advisor, health physics/chemistry technicians, maintenance personnel, and security force personnel. The shift manager on duty has the immediate responsibility for the plant at all times, and has full authority and responsibility for recognizing and declaring emergencies. Each shift is provided with a complement of qualified individuals who have specialized training in the operation of the reactor and other plant systems, plant instrumentation, radiation safety, and maintenance.

The plant manager has full authority and responsibility for the overall supervision and administration of the nuclear plant. Technical support is provided by a staff experienced in reactor physics, nuclear power plant systems technology and operation, and health physics and chemistry. The normal plant operating organiza-

III.A.1.2 Upgrade Emergency Support Facilities

Position (NUREG-0660 Clarification letter dated September 5, 1980)

Each operating nuclear power plant shall maintain an onsite technical support center (TSC) separate from and in close proximity to the control room, that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the TSC. Records that pertain to the as-built conditions and layout of structures, systems, and components shall be readily available to personnel in the TSC.

An operational support center (OSC) shall be established separate from the control room and other emergency response facilities (EOFs) as a place that operations support personnel can assemble and report in an emergency situation to receive instructions from the operating staff. Communications shall be provided between the OSC, TSC, EOF, and control room.

An Emergency Operations Facility (EOF) (near-site) will be operated by the licensee for continued evaluation and coordination of all licensee activities related to an emergency having or potentially having environmental consequences. The EOF must meet habitatability requirements to ensure that personnel can remain in the facility throughout the entire course of the accident including evacuation of the surrounding area. The facility will have sufficient space to accommmodate representatives from Federal, State, and Local governments as appropriate. In addition, the major State and Local response agencies may provide for data analysis jointly with the operator at this location. The Emergency Operations Facility (EOF) will provide information needed by Federal, State and Local authorities for implementation of offsite emergency plans in addition to a centralized meeting location for key representatives from the agencies.

Clarification

None

WNP-2 Position

WNP-2 concurs with the intent of this position and its clarification as described in NUREG-0696 and is implementing the following:

a. Technical Support Center (TSC)

WNP-2 is establishing a habitable, onsite Technical Support Center. The TSC will be complete and functional prior to July 1982, or a temporary location will be established and equipped to fulfill the intent of the functional requirements of the TSC.

Plant status data and communication systems beween TSC, control room and EOF will be completed by July 1982 or temporary subsituations will be implemented to meet the intent of the function requirements. Plant records will be available in the TSC. Procedures will be written to include the accident assessment function that would be conducted in the TSC and control room. Those plant and meterological parameters necessary to conduct the accident assessment and initial emergency response evaluation will be available in the TSC.

The TSC will be designed and constructed to meet the intent of the requirements addressed in NUREG-0578, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, July 1979, and NUREG-0696, Functional Criteria for Emergency Response Facilities.

Design descriptions for the TSC facility, including the plant status data and communication systems, will be provided by November 12, 1981.

b. Operational Support Center (OSC)

An onsite Operational Support Center will be established at WNP-2. Communication will be provided between OSC, TSC, EOF, and the control room. Procedures will be prepared and implemented to establish the responsibilities and management communications for personnel assigned to the OSC. The OSC will be located ~~in the~~ within a Plant ~~Service~~ Building ~~adjacent to the Reactor/Turbine Building.~~ within the security boundary.

c. Emergency Operations Facility (EOF)

The Washington Public Power Supply System's Hanford Site will have a common plant support facility containing EOF space, instrumentation and displays to support the Hanford projects, WNP-2, -1 and -4. The siting of this facility ~~if~~ is described in the Supply System's letter of December 12, 1980 from G. D. Bouchey to B. Grimes. The facility will have adequate protection factors to support habitability throughout the course of an accident.

Design descriptions for the EOF will be provided by November 12, 1981.

d. OSC/TSC/EOF Emergency Plan

The WNP-2 Emergency Plan addresses the OSC/TSC/EOF approaches defined above.

III.D.1.1 Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized Water Reactors and Boiling Water Reactors

Position (NUREG-0737)

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.

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.

WNP-2 Position

WNP-2 has performed a systems design review and will develop 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. A systems review for potential leakage paths outside containment was conducted to determine those systems which penetrate containment and could contain highly radioactive fluids in the case of a serious transient or reactor accident. Three unisolated leak paths were found which could potentially transport highly radioactive fluids. Auto-isolation will be installed on these potential leak paths in support of existing manual, remote isolation capabilities and to maintain radiological consequences to as-low-as-reasonably achievable.

b. A leakage surveillance and preventive maintenance program* will be developed for those systems within secondary containment which could be used to transport highly radioactive fluids in the case of a serious reactor transient or accident. This program includes the following features:

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

2. A system listing identifying the components to be inspected, method of ispection or measurement and frequency or surveillance.

3. Routine operator inspections of visually accessible portions of designated systems at normal operating conditions or test mode.

4. Detailed leakage inspection and measurement 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 posible modifications to keep leakage as-low-as-reasonably achievable.

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*This program is to be initiated prior to July 1982, exception being taken to those systems which cannot be tested until startup due to required plant conditions. Program documentation will be availble onsite for NRC I&E review approximately by April 1982.

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.

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 moitoring 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 asure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

WNP-2 Position

WNP-2 intends to meet the intent of the position defined in this item. To summarize the intent of the program being implemented, six (6) continuous air monitoring systems are provided for air sampling plant areas where personnel may be present during accident conditions. In addition, ten (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 High Volume Air Samplers, both AC and DC powered operation.

During accident conditions activated charcoal cartridges will be used for radioiodine analysis 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 will be purged in a fume hood using plant service air or bottled nitrogen which is stored on site.

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 WNP-2 Emergncy Plan Section 17.

III.D.3.4 Control Room Habitability Requirements

Position

In accordance with Task Action Plan Item III.D.3.4 and control room habitability, licensees shall assure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design basis accident conditions (Criterion 19, "Control Room," of Appendix A, "General Design Criteria for Nuclear Power Plant," to 10 CFR Part 50).

Clarification

a. All licensees must make a submittal to the NRC regardless of whether or not they met the criteria of the referenced Standard Review Plans (SRP) sections. The new clarification specifies that licensees that meet the criteria of the SRPs should provide the basis for their conclusion that SRP 6.4 requirements are met. Licensees may establish this basis by referencing past submittals to the NRC and/or providing new or additional information to supplement past submittals.

b. All licensees with control rooms that meet the criteria of the following sections of the Standard Review Plan:

2.2.1-2.2.2	Identification of Potential Hazards in Site Vicinity
2.2.3	Evaluation of Potential Accidents
6.4	Habitability Systems

shall report their findings regarding the specific SRP sections as explained below. The following docummemts should be used for guidance:

1. Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release";

2. Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release"; and,

3. K. G. Murphy and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19," 13th AEC Air Cleaning Conference, August 1974.

Licensees shall submit the results of their findings as well as the basis for those findings by January 1, 1981. In providing the basis for the habitability finding, licensees may reference their past submittals. Licensees should, however, ensure that these submittals reflect the current facility design and that the information requested in Attachment 1 is provided.

c. All licensees with control rooms that do not meet the criteria of the above-listed references, Standard Review Plans, Regulatory Guides, and other References.

These licensees shall perform the necessary evaluations and identify appropriate modifications.

Each licensee submittal shall include the results of the analyses of control room concentrations from postulated accidental release of toxic gases and control room operator radiation exposures from airborne radioactive material and direct radiation resulting from design basis accidents. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either on the site or within 5 miles of the plant site boundary. Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of control room habitability but is not all inclusive.

The design basis accident (DBA) radiation source term should be for the loss-of-coolant accident (LOCA) containment leakage and engineered safety feature (ESF) leakage contribution outside containment as described in Appendix A and B of Standard Review Plan Chapter 15.6.5. In addition, boiling water reactor (BWR) facility evaluations should add any leakage from the main steam isolation valves (MSIV) (i.e., valve stem leakage, valve seat leakage, main steam isolation valve leakage control system release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering the staff recommendations in Section D of Regulatory Guide 1.96 (Revision 2) regarding MSIV leakage control systems. Other DBAs should be reviewed to determine whether they might constitute a more severe control room hazard than the LOCA.

In addition to the accident analysis results, which should either identify the possible need for control room modifications or provide assurance that the habitability systems will operate under all postulated conditions to permit the control room operators to remain in the control room to take appropriate actions required by General Design Criterion 19, the licensee should submit sufficient information needed for an independent evaluatin of the adequacy of the habitability systems. Attachment 1 lists the information that should be provided along with the licensee's evaluation.

WNP-2 Position

The WNP-2 control room meets the intent of the requirements of the subject SRPs. The control room design description is being reviewed by NRC as part of the WNP-2 FSAR (FSAR 6.4). Information required to permit an independent review is provied in the FSAR.