1.13 TMI-2 RELATED REQUIREMENTS FOR NEW OPERATING LICENSES

1.13.1 NUREG-0737, CLARIFICATION OF THE TMI ACTION PLAN REQUIREMENTS

Following the accident at Three Mile Island Unit 2, the NRC developed the TMI Action Plan, NUREG-0660, to provide a comprehensive and integrated plan for improving the safety of power reactors. NUREG-0737 was issued with an October 31, 1980 letter from D.G. Eisenhut (NRC) to licensees of operating power reactors and applicants for operating licenses forwarding specific TMI-related requirements from NUREG-0660 which have been approved by the NRC for implementation at this time. In this NRC report, these specific requirements comprise a single document which includes additional information about implementation schedules, applicability, method of implementation review by the NRC, submittal dates, and clarification of technical positions. It should be noted that the total set of TMI-related actions have been documented in NUREG-0660, but only those items that the NRC has approved for implementation to date are included in NUREG-0737.

Enclosure 2 to NUREG-0737 lists TMI Action Plan requirements for operating license applicants. Section 1.13.2 itemizes these requirements sequentially according to the NUREG-0737 number. Each item is accompanied by a response and/or reference to a section in the UFSAR that further discusses how the licensee or the LGS design complies with the requirement. These responses were revised periodically as ongoing efforts to address each requirement were completed.

1.13.2 TMI ACTION PLAN REQUIREMENTS FOR APPLICANTS FOR AN OPERATING LICENSE (ENCLOSURE 2 TO NUREG-0737)

- I.A.1.1 SHIFT TECHNICAL ADVISOR

Position

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

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls and the control room. The applicant 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

(1) Due to the similarity in the requirements for dedication to safety, training, and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment function. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.

(2) To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been the STAs must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person who is normally the immediate supervisor of the shift supervisor to STA duties as defined herein.

(3) It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the 10 minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence.

We do not intend, at this time, to specify or advocate a minimum time onsite.

Response

See Section 13.1.2.1.1 for discussion of the STA position. Qualification requirements for STA positions are discussed in Section 13.1.3.1.

- I.A.1.2 SHIFT SUPERVISOR RESPONSIBILITIES

Position

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room.

Clarification

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

(2) Plant procedures shall be reviewed to 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:

(a) 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 principle shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

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

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

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

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

Response

In the assignment of functions to the Shift Manager, consideration is given to aspects such as the need to keep the Shift Manager in control of and aware of plant operational, maintenance, and testing activities which may affect safe operation and the need to prevent administrative duties from detracting from the primary responsibility of assuring safe operation.

A letter was written by S.L. Daltroff (PECo) on December 26, 1979, which defines and emphasizes the primary management responsibility of the Shift Superintendent (now the Shift Manager). Similar to PBAPS, this letter will be promulgated to shift supervision in the form of an administrative procedure.

The letter referenced above also defined the duties of control room operators. The nature of the letter was not only to define and emphasize responsibility but to effect the establishment of a definite line of command. This letter will form the basis for an administrative procedure in which the duties of the control room operator will be defined.

In the administrative procedure covering shift operations, a directive will be written which will specify who can relieve the Shift Manager. It will require only that a member of Shift Supervision bearing an active senior license and qualified as an Emergency Director will have such an authority.

Temporary relief of the Shift Manager will normally be accomplished using the Shift Supervisor. Duties and responsibilities, similar to those of the Shift Manager, will be defined in the administrative procedure covering shift operations. He will be a senior licensed individual having worked side-by-side with the Shift Manager, fully knowledgeable of the Shift Manager's responsibilities and the overall plant status at any given time.

The licensee is engaged in a Management Development Program, which includes management training for shift supervisors. All management training courses include training in such topics as style of management, planning, delegation, communications, motivation, personnel and industrial relations and performance review. In addition, all shift supervision has, or will have prior to startup, completed the Genco II Kepner Tregoe Course in Decision Making. In the future, it is planned that shift supervision will have the opportunity to attend some of the subsequent courses associated both with the Management Development Program and the Kepner Tregoe Program.

The administrative responsibilities for all members of shift supervision are defined in an administrative procedure.

The administrative procedure covering shift operations will define shift supervision's administrative responsibilities. Those which will be retained will be those which are defined in that administrative procedure.

The duties and responsibilities of the Shift Manager during accident/transient conditions will be delineated in both the Emergency Plan and the administrative procedures governing shift operations. The procedures developed from the Emergency Plan will contain detailed responsibilities of the Shift Manager during such conditions.

The STA will hold a staff position in the Operations Group. He reports directly to the Shift Manager on his staff. The STA advises the Shift Manager concerning off-normal events and will make appropriate recommendations regarding corrective and precautionary actions.

See Section 13.1.2.1.1 for further discussion.

- I.A.1.3 SHIFT MANNING

Position

Assure that the necessary number and availability of personnel to man the operations shifts have been designated by the licensee. Administrative procedures should be written to govern the movement of key individuals about the plant to assure that qualified individuals are readily available in the event of an abnormal or emergency situation. This should consider the recommendations on overtime in NUREG-0578. Provisions should be made for an aide to the shift supervisor to assure that, over the long-term, the shift supervisor is free of routine administrative duties.

Clarification

At any time a licensed nuclear unit is being operated in Modes 1-4 for a PWR (power operation, startup, hot standby or hot shutdown, respectively) or in Modes 1-3 for a BWR (power operation, startup, or hot shutdown, respectively), the minimum shift crew shall include two licensed senior reactor operators, one of whom shall be designated as the shift supervisor, two licensed reactor operators, and two unlicensed auxiliary operators. For a multiunit station, depending upon the station configuration, shift staffing may be adjusted to allow credit for licensed senior reactor operators and licensed reactor operators to serve as relief operators on more than one unit; however, these individuals must be properly licensed on each such unit. At all other times, for a unit loaded with fuel, the minimum shift crew shall include one shift supervisor who shall be a licensed senior reactor operator, one licensed reactor operator, and one unlicensed auxiliary operator.

Adjunct requirements to the shift staffing criteria stated above are as follows:

(1) A shift supervisor with a senior reactor operator's license, who is also a member of the station supervisory staff, shall be onsite at all times when at least one unit is loaded with fuel.

(2) A licensed senior reactor operator shall, at all times, be in the control room from which a reactor is being operated. The shift supervisor may from time to time act as relief operator for the licensed senior reactor operator assigned to the control room.

(3) For any station with more than one reactor containing fuel, the number of licensed senior reactor operators onsite shall, at all times, be at least one more than the number of control rooms from which the reactors are being operated.

(4) In addition to the licensed senior reactor operators specified in (1), (2), and (3) above, for each reactor containing fuel, a licensed reactor operator shall be in the control room at all times.

(5) In addition to the operators specified in (1), (2), (3), and (4) above, for each control room from which a reactor is being operated, an additional licensed reactor operator shall be onsite at all times and available to serve as relief operator for that control room. As noted above, this individual may serve as relief operator for each unit being operated from that control room, provided he holds a current license for each unit.

(6) Auxiliary (nonlicensed) operators shall be properly qualified to support the unit to which assigned.

(7) In addition to the staffing requirements stated above, shift crew assignments during periods of core alterations shall include a licensed senior reactor operator to directly supervise the core alterations. This licensed senior reactor operator may have fuel handling duties but shall not have other concurrent operational duties.

Licensees of operating plants and applicants for operating licenses shall include in their administrative procedures 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.

The following information regarding fatigue management and work hours controls is historical. The current regulatory requirements are provided by the 10CFR26 Fitness for Duty Programs rule, which became effective on April 30, 2008. Implementation of the amended rule was required by October 1, 2009. Limerick administrative procedure LS-AA-119, "Fatigue Management and Work Hour Limits," was revised and issued to implement requirements for managing fatigue and controlling work hours in accordance with 10CFR26, Subpart I, "Managing Fatigue." The procedure defines the scope of workers that are subject to the fatigue management program and the scope of workers subject to work hour controls. The procedure also includes the 10CFR26 work hours limits.

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

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions. The guidance contained in IE Circular No. 80-02 was amended by the

July 31, 1980 NRC letter. In turn, the overtime guidance of the July 31, 1980 NRC letter was revised in Section I.A.1.3 of NUREG-0737. The NRC was issued a policy statement which further revises the overtime guidance as stated in NUREG-0737. This guidance is as follows:

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

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

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

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

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

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

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

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

Response

See Section 13.1.2 on shift manning.

The shift operations administrative procedure governs the required shift staffing and movement of key individuals about the plant, in particular the location of control operators and shift supervision.

An administrative procedure contains, working hour restrictions, which are in accord with current regulations at the time of writing.

The same administrative procedure that sets forth policies regarding overtime contains procedures which govern the deviation from overtime restrictions and how deviations will be documented.

The operations shift complement required when refueling operations are scheduled, along with the responsibilities of the refueling shift personnel, are defined in administrative procedures.

The licensee maintains a Nuclear Training Division. This organization compiles specific job requirements for operating people within power plants. For this list of job requirements, qualifying tests are generated. These tests are administered to applicants for promotion, with promotion to the applicable job described being contingent upon a passing grade. This applies to all plant operators including the equipment operator.

- I.A.2.1 IMMEDIATE UPGRADING OF OPERATOR AND SENIOR OPERATOR TRAINING AND QUALIFICATION

Position

Applicants for SRO license shall have 4 years of responsible power plant experience, of which at least 2 years shall be nuclear power plant experience (including 6 months at specific plant) and no more than 2 years shall be academic or related technical training. After fuel loading, applicants shall have 1 year of experience as a licensed operator or equivalent.

Certifications that operator license applicants have learned to operate the controls shall be signed by the highest level of corporate management for plant operation.

Applicants must revise training programs to include training in heat transfer, fluid flow, thermodynamics, and plant transients.

Clarification

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

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

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

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

The track followed by a high school graduate (a nondegreed individual) to become an SRO would be 4 years as a control room operator, at least one of which would be as a licensed operator, and participation in an SRO training program that includes 3 months on-shift as an extra person.
The track followed by a degree-holding engineer would be, at a minimum, 2 years of responsible nuclear power plant experience as a staff engineer, participation in an SRO training program equivalent to a cold applicant training program, and 3 months on-shift as an extra person in training for an SRO position.

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

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

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

Response

Applicants for SRO license will have at least 4 years of responsible power plant experience, of which at least 2 years will be nuclear plant experience, including 6 months at the plant and no more than 2 years will be academic or related technical training.

The requirements for certification are implemented in administrative procedures.

The training programs for RO and SRO license will include training in heat transfer, fluid flow, thermodynamics, and plant transients. See Section 13.2.1.1 for further discussion.

- I.A.2.3 ADMINISTRATION OF TRAINING PROGRAMS

Position

Pending accreditation of training institutions, training instructors who teach systems, integrated response, transient and simulator courses shall successfully complete a SRO examination prior to fuel loading and instructors shall attend appropriate retraining programs that address, as a minimum, current operating history, problems and changes to procedure and administrative limitations. In the event an instructor is a licensed SRO, his retraining shall be the SRO requalification program.

Clarification

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

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

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

Response

The requirements for training instructors will be implemented in administration of the training program.

- I.A.3.1 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS

Position

Applicants for operator licenses will be required to grant permission to the NRC to inform their facility management regarding the results of examinations.

Contents of the licensed operator requalification program shall be modified to include instruction in heat transfer fluid flow, thermodynamics and mitigation of accidents involving a degraded core.

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license.

Requalification programs shall be modified to require specific reactivity control manipulations. Normal control manipulations, such as plant or reactor startups, must be performed. Control manipulations during abnormal or emergency operation shall be walked through and evaluated by a member of the training staff.

An appropriate simulator may be used to satisfy the requirements for control manipulations.

Clarification

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

The clarification does provide additional preparation time for utility companies and NRC to meet 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 in June 1, 1980 to applicants where a simulator is located at the facility. Starting October 1, 1981, simulator examinations will be conducted for applicants of facilities that do not have simulators at the site.

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

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

Response

The requirements for RO and SRO examinations and requalification programs will be implemented.

- I.B.1.2 EVALUATION OF ORGANIZATION AND MANAGEMENT

Position

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

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

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

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

Utility management shall establish a group, independent of the plant staff, but assigned onsite, to perform independent reviews of plant operational activities. The main functions of this group will be to evaluate the technical adequacy of all procedures and changes important to the safe operation of the facility and to provide continuing evaluation and assessment of the plant's operating experience and performance.

<u>Response</u>

The licensee’s corporate and plant staff organizations for routine operations are described in Sections 17.2 and 13.1. The emergency organization is described in the nuclear emergency plan. Independent review activities are described in Section 13.4

- I.C.1 <u>SHORT-TERM ACCIDENT ANALYSIS AND PROCEDURE REVIEW</u>

<u>Position</u>

In our letters of September 13 and 27, October 10 and 30, and November 9, 1979, we 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, and to conduct operator retraining (see also Item I.A.2.1 of this report). 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 were included in NUREG-0737, Item I.C.1.

Pending staff approval of the revised analysis and guidelines, the staff will continue the pilot monitoring of emergency procedures described in Item I.C.8 (NUREG-0660). The adequacy of the BWR vendor's guidelines will be identified to each near-term operating licensee during the emergency procedure review.

<u>Response</u>

Emergency operating procedures are developed from the BWROG Emergency Procedure and Severe accident Guidelines (EPG/SAGs). Reference UFSAR Section 15.0.6 for a discussion of these guidelines. The development of the EPGs was based on reanalysis of transients and accidents and inadequate core cooling. The licensed operator training program includes training on the emergency operating procedures.

Additional information has been provided in a letter from V.S. Boyer (PECo) to D.G. Eisenhut (NRC) dated April 15, 1983.

- I.C.2 SHIFT RELIEF AND TURNOVER PROCEDURES

Position

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

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

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

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

(c) Identification 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.

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

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

Response

The requirements stated in this section will be implemented except for the request to establish separate checklists or logs for use by the offgoing and ongoing equipment operators and maintenance technicians.

A variety of shift turnover checklists or logs, situated in various locations of the plant and under the control of many groups would further hinder the transfer of vital information to the operating shift personnel with primary responsibility for plant operations. A limited number of checklists or logs, centralized in the control room and under the supervision of control room personnel, is essential to effective transfer of information.

Maintenance and testing of equipment vital to safe operation of the plant is performed with the knowledge and approval of the appropriate licensed control room operator. The checklists, status boards, or logs will be utilized to identify 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. Some of this information will be supplied to the control room operators and supervisors, as appropriate, by the equipment operators and technicians for entry into the checklists and logs. Shift personnel meetings under the direction of shift supervision are normally held shortly after shift turnover. Offgoing equipment operators will normally be relieved at their job locations in the plant. Equipment operators will, when job conditions permit, complete and review an applicable shift turnover checkoff list. If plant operations require that equipment operators conduct shift turnover on the job away from their normal turnover location and no turnover checklist is executed, the person making relief will, at the earliest convenience, report to shift supervision to obtain a supplementary briefing. Examples of activities that could preclude normal turnover include filling the main generator with hydrogen and executing a demineralizer regeneration.

Checklists for oncoming and offgoing control room operators and oncoming shift supervisors to be used during shift turnover will be included in administrative procedure for shift operations.

A checklist for shift turnover to be used by equipment operators will be written and will be included in the shift operations administrative procedure.

Included as part of the shift operations administrative procedure, and specifically in the sections relating to shift turnover, instructions will be communicated to the various levels of shift operating personnel directing that, when deficiencies in the turnover process are noticed primarily by the discovery of information which was not surfaced during the turnover, such deficiencies will be brought to the attention of shift supervision, who will in turn initiate a modification to the turnover checkoff list. This mechanism will ensure that, as job responsibilities change, appropriate modifications will be made to the checklist.

- I.C.3 SHIFT SUPERVISOR RESPONSIBILITIES

This item is included with Section I.A.1.2, Shift Supervisor responsibilities.

Response

This requirement will be implemented.

- I.C.4 CONTROL ROOM ACCESS

Position

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

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

(2) Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons

possessing a current 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 the control room.

Response

An administrative procedure for control room access will be written and will define the authority and responsibility of the Shift Manager, or alternate, to exercise control over control room access. This administrative procedure will provide the Shift Manager, or alternate, with authority to order persons out of the control room if they have gained entrance and were not authorized or if conditions in the control room change to an extent which changes the access requirements.

Administrative procedures establish a clear line of authority and responsibility in the control room for emergency conditions. This will include the line of succession for the person in charge of the control room.

During plant emergencies, lines of communications and authority for the subject plant management personnel will be delineated in the Emergency Plan. This will include those persons reporting to the TSC, EOF, and Press Facility.

- I.C.5 FEEDBACK OF OPERATING EXPERIENCE

Position

Each licensee will review its administrative procedures to assure that operating experience from within and outside the organization is continually provided to operators and other operational personnel and is incorporated in training programs.

Response

The Regulatory Assurance Section is supervised by the Manager, Regulatory Assurance, who reports to the Vice President, LGS and is responsible for ensuring review of operating experience reports that may be directed to the plant by various industry groups and regulatory agencies and for disseminating such reports to the appropriate personnel for review for applicability to LGS and determination of required action.

In addition, the External and Internal Operating Experience (OPEX) program ensures that appropriate events that occur within the Exelon fleet and in the industry are evaluated for similar conditions at the station. To ensure consistency between various plants within the Exelon fleet, a corporate OPEX coordinator provides overall coordination and direction to this program. Mechanisms exist for identifying, screening, and investigating OPEX items. The corporate OPEX coordinator screens OPEX issues. Depending on the OPEX item being investigated, appropriate corporate, station or other qualified personnel evaluate the issue. Corporate actions are identified if required and are tracked for completion within the site action tracking program. Appropriate status reporting and monitoring of OPEX are also performed. The site OPEX coordinator function resides within Regulatory Assurance.

- I.C.6 VERIFY 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.

Response

Plant procedures will describe a system for the control of removal and restoration and alignment of safety-related plant systems or equipment. This system will use a combination of control room indicators, operability testing, or independent verification (subject to radiation exposure limitations), to ensure that equipment is in its correct alignment.

- I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

Position

Obtain NSSS vendor review of power ascension and emergency operating procedures to further verify their adequacy.

Response

This requirement will be implemented.

- 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., SBA, loss of feedwater, restart of ESF following a loss of ac power and steam line break).

Response

Information on emergency procedures (NUREG-0737, Item I.C.1) was provided to the NRC in a response (Letter from V.S. Boyer to D.G. Eisenhut dated April 15, 1983) to Generic Letter 82-33, Supplement 1 to NUREG-0737. Emergency operating procedures are developed from the current revision of the BWROG Emergency Procedure Guidelines.

- I.D.1 CONTROL ROOM DESIGN REVIEWS

Position

Licensees and applications for operating licenses are 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. Those applicants for operating licenses who are unable to complete this review prior to issuance of a license shall make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule approved by us for correcting deficiencies. These applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Clarification

Applicants for operating license who will be unable to complete the detailed control room 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. We will evaluate the applicant's preliminary assessments including the performance by us of onsite reviews/audits. Our onsite review/audit will be on a schedule consistent with applicant licensing needs and will emphasize the following aspects of the control room:

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

(2) The groupings of displays and the layout of panels;

(3) Improvements in the safety monitoring and human factors enhancement of controls and control displays;

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

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

(6) The operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems;

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

(8) The categorization of alarms, with unique definition of safety alarms;

(9) The physical location of the shift supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, we 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.

Response

The CRDR effort directed by Item I.D.I and required by Supplement 1 to NUREG-0737 began in 1980 with the licensee's participation in the BWROG CRDR Subcommittee. The subcommittee produced a BWR Owner's Group Generic CRDR Program which addresses Item 5.1.b of Supplement 1. This generic program was submitted to the NRC for review in August 1981. The review and subsequent discussions between the NRC and representatives of the subcommittee have resulted in a supplement to the review program.

A preliminary review of the LGS control room was conducted using the original design review program in October 1981. At that time, the LGS control room was still in the construction phase, and the formal LGS emergency procedures were not available for the walk-through.

The licensee subsequently developed a program to address the assessment, implementation and verification phases of the LGS CRDR Program. This program was submitted in August 1983 and a report was submitted in June 1984 and supplemented in November 1984 and June 1985.

Basic Requirements Completion Dates:

(Numbering refers to corresponding portions of Section 5 of Supplement 1)

5.1.a) As was the case during the initial review phase, a person competent in human factors engineering as well as persons competent in system design and system operation were included in the assessment phase of the Program. This assessment was completed in April 1984.

5.1.b) A detailed review of the control room has been completed as discussed in current status above. Completion of the review to address the supplemental checklist and those items not included in the preliminary review due to construction status was completed in January 1984.

5.1.c) Assessment of the HEDs was completed in June 1985.

5.1.d) Proposed improvements have been reviewed by the multidisciplinary task force described in 5.1.a to ensure that the proposed change addresses the identified HED and does not create additional HEDs. All changes have been integrated with other control room modifications.

5.2.a) The program plan for completing the CRDR was completed and is outlined below:

i. Completed the generic review program including the supplemental review and the emergency procedure walk- through.

ii. Assessed the identified HEDs and generated recommendations for modification to those HEDs that warrant a change.

iii. Each of the proposed modifications were reviewed to verify that it corrected the HED it was intended to correct and did not create any new unacceptable HEDs. The modifications have been coordinated with the balance of the NUREG-0737 Supplement 1 initiatives.

iv. The NRC conducted an in-progress audit in December 1983.

5.2.b) A summary report was prepared and submitted in June 1984 and supplemented in November 1984 and June 1985. These reports included proposed modifications and their Unit 1 schedules. Unit 2 modifications and schedules were provided in October 1988.

- I.D.2 PLANT SAFETY PARAMETER DISPLAY CONSOLE

Position

Each applicant and licensee shall install a 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.

Response

The LGS design includes a PMS. This system is based, in part, on the GE emergency response system described in Reference 1.13-7. The SPDS is a part of this PMS. The SPDS is not safety-related, as discussed in Supplement 1 to NUREG-0737. Sensors, isolators, signal conditioners or other components which provide input to the SPDS are Q-listed if they are part of a safety-related system. The SPDS parameters, a subset of the parameters available in the PMS data base, are based on the Regulatory Guide 1.97 (Rev 2) BWR parameter list. All of the critical safety functions defined in Supplement 1 to NUREG-0737, "Clarification of TMI Action Plan Requirements," for a BWR, are addressed by the PMS process variables.

The parameters included in the SPDS display are based on the entry conditions for the LGS EOPs. As changes and improvements are made to the RPV control and containment control procedures, the system can be modified to reflect these changes. The system has been designed in accordance with the guidance provided in NUREG-0696.

A safety analysis describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events was transmitted by letter from J.S. Kemper (PECo) to A. Schwencer (NRC) dated September 2, 1983.

The software debugging, validation, testing, and acceptance testing will be completed during the Power Ascension Test Program. The SPDS and Regulatory Guide 1.97 parameter displays will be functional within 30 days after the completion of the 100 hour warranty run at 100% power.

- I.G.1 TRAINING DURING LOW POWER TESTING

Position

We require applicants for a new operating license to define and commit to a special low power testing program approved by NRC to be conducted at power levels no greater than 5% for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training.

Clarification

Chapter 14 of the Final Safety Analysis Report describes the applicant's initial test program. The objectives of the initial test program include both training and the acquisition of technical data. This program has been determined by the staff to be acceptable as reported in Section 14 of this report. However, we require the applicant to perform additional testing and training beyond the requirements of the initial test program.

Response

The BWROG program for compliance with NUREG-0737 Requirement I.G.1 was transmitted to the NRC via letter (BWROG-8120) from D.B. Waters (BWROG) to E.G. Eisenhut (NRC). The generic program described in this document is divided into five sections: I-Preoperational Testing; II-Cold Functional Testing; III-Hot Functional Testing; IV-Startup Testing; and V-Additional Training and Testing. The initial test program for LGS as described in Chapter 14 follows the testing described in the first four sections of the BWROG program. During this program, the licensee expects to perform significant plant transients only once, but with a maximum of licensed personnel in attendance. The LGS unit unique simulator provides an excellent mechanism for training people without affecting the real plant. Repetition of startup tests solely for testing purposes will be done on this simulator. Chapter 14 has been changed to describe the additional testing discussed in section V of the BWROG program.

Additional training is to be included in the certification program on the LGS simulator which shall include total loss of offsite and onsite ac power.

- II.B.1 REACTOR COOLANT SYSTEM VENTS

Position

Each applicant and licensee shall install RCS and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a 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 10CFR50, Appendix A, "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:

(1) Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCA initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10CFR50.46.

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

Clarification

A. General

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

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

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

(4) Where practical, the reactor coolant system vents should be kept smaller than the size corresponding to the definition of LOCA (10CFR50, Appendix A). This will minimize the challenges to the ECCS since the inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation, although it may result in leakage beyond technical specification limits. On PWRs, the use of new or existing lines whose smallest orifice is larger than the LOCA definition will require a valve in series with a vent valve that can be closed from the control room to terminate the LOCA that would result if an open vent valve could not be reclosed.

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

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

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

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

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

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

(11) Provisions to test for operability of the reactor coolant vent system should be a part of the design. Testing should be performed in accordance with 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 BWROG has suggested that the present BWR designs have an inherent capability to vent, a question relating to the capability of existing systems arises. The ability of these systems to vent the RCS of noncondensable gas generated during an accident must be demonstrated. Because of differences among the head vent systems for BWRs, each licensee or applicant should address the specific design features of this plant and compare them with the generic venting capability proposed by the BWROG. In addition, the ability of these systems to meet the same requirements as the PWR vent system must be documented.

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

<u>Response</u>

The BWROG position on NUREG-0737, Item II.B.1 requirements for RCS vents is contained in D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981, D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated October 8, 1980, and T.D. Keenan (BWROG) letter to D.G. Eisenhut (NRC) dated October 17, 1979. The licensee concurs with the BWROG conclusion that adequate RCS venting capability is provided by the existing plant design. The following is a description of the existing LGS provisions for RCS venting and an assessment of this capability relative to the NUREG-0737 position and clarification.

Position (1)

LGS is provided with five power-operated, safety-grade SRVs (ADS valves PSV-41-F013E, H, K, M, and S) that would be the primary means of venting noncondensable gases from the RPV following a LOCA. The point of connection of the vent lines to the vessel is such that accumulation of gases above this elevation in the vessel will not inhibit natural circulation cooling of the reactor core. These ADS valves are self-actuating at their set relieving pressure to provide system overpressure protection and can also be actuated automatically or manually from the control room to depressurize the reactor. Operation of the ADS valves requires only safety-grade equipment and controls and does not require any source of offsite or ac power. The valves are controlled by dc power from the safeguard batteries and are pneumatically actuated from individual safety-grade accumulators and a safety-grade nitrogen bottle supply for long-term operation. Additional information regarding the design, qualification, power source, etc., of the SRVs is presented in Sections 5.1, 5.2.2, 6.2, 6.3, 7.3, 9.3.1.3, and 15.

Although the power-operated, safety-grade SRVs discussed above satisfy the NUREG-0737 requirements, the following other means of venting noncondensables from the RPV exist:

a) Nine other SRVs (PSV-41-F013 A-D, F, G, J, L, and N) are provided. These valves are identical to those used for ADS except that they are not equipped for automatic actuation or provided with safety-grade air supplies. They may be individually operated from the control room provided that the normal instrument air supply is available. Normally open reactor head vent line 2"- DBA-108 discharges to main steam line "C", which can then be vented to the suppression pool by opening any of the three SRVs on that line.

b) Normally closed reactor vessel head vent valves (2"-HV-41-F001 and F002) are provided. These motor- operated valves are operable from the control room, provided that the normal power supplies are available. The head vent lines discharge to the drywell equipment drain tank.

c) The main steam-driven HPCI and RCIC system turbines exhaust to the suppression pool. These will function automatically to ensure adequate core cooling, as discussed in Sections 6.3 and 5.4 and, in the process, provide continuous venting of noncondensables to the suppression pool during their operation. The effect of noncondensables in the HPCI and RCIC turbine steam has been analyzed and the results are described in the D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981.

The effects of inadvertent opening of a SRV or both head vent valves would be the same as a small steam line break. A complete steam line break is part of the plant's design basis, and smaller size breaks have been shown to be of lesser severity. A number of reactor system blowdowns due to SORV have confirmed this. Similarly, a break in any of the systems enumerated above would be less severe than a complete steam line break. Because the results of the complete steam line break analysis have demonstrated compliance with the acceptance criteria of 10CFR50.46, no new analyses are required to show conformance with 10CFR50.46 for vent line failures.

Position (2)

In the development of the BWR EPG, this issue was considered. The EPG regarding reactor vessel level control addresses all contingent actions required to maintain RPV level. These actions include venting for all instances when the accumulation of noncondensables may be of concern. Further discussion of this issue is contained in the D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981.

Clarification A(1)

The automatic and/or manual operation of the RCS vent paths described above provides effective venting capability to deal with large quantities of noncondensable gas. This venting capability will preclude the possibility of noncondensable gas accumulation interfering with core cooling.

Clarification A(2)

The BWR EPG include provisions for RCS venting for all instances when the accumulation of noncondensables may be of concern. This topic is further discussed in the D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981. As stated in the response to Position (1), the use of these vent paths or their failure will not result in a violation of the requirements of 10CFR50.46.

An analysis demonstrating that the direct venting of noncondensable gases into the primary containment will not result in violation of combustible gas concentration limits is presented in Section 6.2.5. The gas generation rates assumed in this analysis are in accordance with 10CFR50.44 and Regulatory Guide 1.7.

Clarification A(3)

Because the containments are inerted, and postaccident combustible gas control is maintained by oxygen deficiency, the LGS design is insensitive to the rate or extent of metal-water reaction up to the point where containment pressurization is limiting. This point is substantially beyond the present Regulatory Guide 1.7 design basis as demonstrated by the conservative assessment of this margin provided in Sections 6.2.1.3.4 and 6.2.5.

Further consideration will be given to the impact of combustible gas source terms beyond the present design basis in response to the proposed NRC degraded core rulemakings.

Clarification A(4)

As stated in the response to Position (1), a failure of one of the above vents would result in the equivalent of a small steam line break LOCA.

Clarification A(5)

SRV position indication is provided in the control room by the acoustic monitoring system described in Section 7.6.1.5. Direct position indication is provided in the control room for the HPCI, RCIC, and head vent valves.

Clarification A(6)

Each SRV, HPCI, RCIC, and head vent valve may be individually operated from the control room.

Clarification A(7)

All design requirements for the RCPB have been met in the design of appropriate portions of each vent path described above. Because inadvertent operation of a vent path will cause only a minor plant transient as described in the response to Position (1), redundancy is not felt to be necessary. Compliance with 10CFR50.46 is assured for all events as described in the response to Position (1).

Clarification A(8)

Block valves are not provided on the SRV lines in accordance with the clarification. The isolation provisions for the HPCI and RCIC steam lines will withstand a single active failure. Such provisions are not felt to be necessary for the head vent valves for the reasons discussed in the response to clarification A(7).

Clarification A(9)

The point within primary containment to which noncondensables are vented is not of concern because the containment is inerted and effective mixing is assured. Mixing of gases within the primary containment is discussed in Section 6.2.5.2.3.

Clarification A(10)

The equipment, piping, controls, and position indication associated with the ADS SRV and HPCI vent paths described above have been environmentally qualified in accordance with Commission Order and Memorandum CLI-80-21 and seismically analyzed as described in Chapter 3. Portions of the RCIC and the head vent line required for venting are also designed to withstand seismic accelerations. The RCIC valves are environmentally qualified to achieve containment isolation.

Clarification A(11)

The SRVs and the HPCI and RCIC steam valves are tested in accordance with 10CFR50, Appendix J and the intent of subsection IWV of Section XI of the ASME B&PV Code.

Clarification A(12)

This clarification does not apply because no new equipment is being provided to meet the RCS venting requirements.

Clarification B(1)

The information provided above and in the referenced letters demonstrates that the LGS ADS SRVs meet all of the BWROG implementation criteria and NRC requirements for RCS venting.

Clarification B(2)

The following ECCS are available for maintenance of reactor vessel water level at LGS.

a. HPCI

b. RCIC

c. LPCI

d. CS

None of the operating modes of the above systems require venting other than from the reactor vessel.

LGS is not equipped with isolation condensers.

- II.B.2 PLANT SHIELDING

The information in the position and response is historical and represents the original plant design requirements based on source terms consistent with TID-14844. The application of Alternative Source Terms (AST) per Regulatory Guide 1.183 has resulted in the re-assessment of control room and off-site radiological consequences from design basis accidents. Shielding design remains on the TID-14844 source terms; however, Regulatory Guide 1.183 source terms may be used for re-evaluations.

Position

With the assumption of a postaccident release of radioactivity equivalent to that described in Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," and Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors" (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, MCCs, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during postaccident operations of these systems.

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

Clarification

The purpose of this item is to ensure that licensees examine their plants to determine what actions can be taken over the short-term to reduce radiation levels and increase the capability of operators to control and mitigate the consequences of an accident. The 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 purposes of this evaluation, vital areas and equipment are not necessarily the same vital areas or equipment defined in 10CFR73.2 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, TSC, sampling station, and sample analysis area must be included among those areas where access is considered vital after an accident. (Refer to section III.A.1.2 of this report for discussion of the TSC and EOF.) 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), MCCs, 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 modification 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 postaccident operations in the vital areas, the following guidance is to be used by licensees to evaluate the adequacy of radiation protection to the operators:

(1) Source Term

The minimum radioactive source term should be equivalent to the source terms recommended in Regulatory Guides 1.3, 1.4, 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," and SRP 15.6.5 with appropriate decay times based on plant design (i.e., assuming the radioactive decay that occurs before fission products can be transported to various systems).

(a) 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 RHR, HPCI, and LPCI, or the equivalent of these systems. In determining the source term for recirculated, depressurized cooling water, assuming that the water contains no noble gases.

(b) 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.

(2) Systems Containing the Source

Systems assumed in your analysis to contain high levels of radioactivity in a postaccident situation should include, but not be limited to, containment, RHR system, safety injection systems, chemical and volume control system, containment spray recirculation system, sample lines, gaseous radwaste systems, and SGTS (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 section III.D.1.1, "Primary Coolant Outside Containment." Liquid waste systems need not be included in this analysis. Modifications to liquid waste systems will be considered after completion of section III.D.1.4, "Radwaste System Design Features To Aid in Accident Recovery and Decontamination."

(3) Dose Rate Criteria

The design dose objectives 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 objectives dose rates are average rates in the area. Local hot spots may exceed the dose rate guidelines. These doses are design objectives and are not to be used to limit access in the event of an accident.

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

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

(4) Radiation Qualification of Safety-Related Equipment

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

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

(b) LOCA events in which the primary system may not depressurize should consider the source term (100% noble gases, 50% iodines, and 1% particulates) to remain in the primary coolant. This method is used to determine the qualification doses for equipment in close proximity to recirculating fluid systems inside and outside of containment. Non-LOCA events both inside and outside of containment should use 10% noble gases, 10% iodines, and 0% particulate as a source term. Table 1.13-6 summarizes these considerations.

Response

A. Introduction

The design review of plant radiation and shielding was performed as required by NUREG-0737 Item II.B.2 and is described below. The purpose of the review was to identify potential problem areas and equipment which may require the development of special postaccident procedures, installation of additional permanent or temporary shielding, relocation of components or piping, or requalification of components.

Areas that are vital for postaccident occupancy or operation and all safety-related equipment were evaluated to determine if access and performance of required operator activities or equipment functions might be unduly impaired due to the presence of the postulated radiation source in the selected systems. Systems required or postulated to process highly radioactive fluids or gases outside the containment during postaccident conditions were selected for evaluation. Radiation levels in adjacent plant areas due to contained sources in piping and equipment of these systems were estimated. Airborne sources caused by leakage from the primary containment and systems containing postaccident sources were also included in the evaluation for vital areas as described below.

The identification of vital areas and a summary of the methodology used to determine radiation doses for these areas and to equipment are presented below. Doses to personnel in vital areas and access paths are listed in Tables 1.13-1 and 1.13-2, respectively. The identification of essential equipment, doses to equipment used for qualification purposes, and the results of the review of equipment for the postulated radiation sources are provided in the separate EQR. The results of the shielding design review for vital areas are provided below in Section H.

B. Vital Area Identification

Areas which may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident are designated as vital areas. A review of LGS was made which determined that the following areas should be designated vital areas.

Continuous Occupancy

1) Main Control Room

2) Technical Support Center

3) Operations Support Center

4) Security Center

Infrequent Occupancy

1) Counting Room

2) Radiochemistry laboratory

3) Postaccident sampling station

4) North stack instrument room

5) HVAC panels at el 304'

6) Radwaste control room

7) Diesel generator area

Potential vital areas that are not listed above were excluded for the following reasons. The post-LOCA hydrogen control (recombiner) system and containment isolation valves are all automatic or remotely controlled by the operator in the main control room and require no local access. There is no manual ECCS alignment area at LGS. Instrument panels and MCCs are not included because the control and alignment of essential systems are accomplished from the main control room and require no local action.

Eleven access paths to vital areas were also identified and included in this review.

C. Selection of Systems for Radiation and Shielding Review

A review was made to determine which systems could be required to operate and/or could be expected to contain highly radioactive materials following an accident where substantial core damage has occurred. The results of this review are presented below.

1. CS, HPCI, RCIC, RHR, and Safeguard Piping Fill Systems.

The CS, RHR, HPCI (water side), RCIC (water side), and safeguard piping fill systems would contain suppression pool water being injected to the RCS. Although the HPCI and RCIC systems could also carry condensate, suppression pool water was assumed for this review for conservatism. The steam sides of the HPCI and RCIC systems would operate on reactor steam.

2. RHR System (Shutdown Cooling Mode)

The RHR system recirculates reactor water when it operates in the shutdown cooling mode. Before operation in this mode can be initiated, the reactor must be depressurized to less than 75 psig. This depressurization is expected to remove substantially all of the noble gases released into the reactor water. Following an accident, the HPCI, RCIC, RHR (LPCI mode), and CS systems would inject water into the RCS. This water from the condensate tank and/or the suppression pool would dilute the reactor water prior to the initiation of shutdown cooling with the RHR system. This review assumed that there are no noble gases in the reactor water in the RHR system for the shutdown cooling mode and that the reactor water is diluted by the suppression pool water volume.

3. CRD System

The operation of the CRD system was reviewed to determine if the scram discharge headers will contain highly radioactive water following an accident. It was determined that they will not. Prior to a scram, the CRD housings contain condensate water delivered by the CRD pumps. When a scram occurs, some of this condensate water from the CRD is discharged to the scram discharge header. After the scram, some condensate and reactor water flows to the scram discharge header until it is completely filled. This takes a matter of seconds. Since the vents and drains in the scram discharge header are isolated by the scram, all discharge flow then stops.

Since it is not reasonable to assume that significant core damage occurs in the first few seconds following a scram, the scram discharge header will contain only a mixture of condensate and preaccident reactor water following this postulated accident.

4. RWCU System

For an accident with resulting core damage, the RWCU system would be isolated and would contain no highly radioactive materials beyond the second isolation valve. On a BWR this system is not needed for RCS venting. It would not be practical to use it for accident recovery after a major accident. It was therefore assumed that this system would not operate with highly contaminated reactor water.

5. Gaseous Radwaste System

For an accident with resulting core damage, it would not be practical to use the gaseous radwaste system for accident recovery. Noble gas isotopes with long lives would cause excessive offsite doses if the gaseous radwaste system was used after a design basis accident. It was therefore assumed that this system would not operate.

6. Postaccident Sampling System

Sampling lines used after an accident would contain primary containment gas, secondary containment gas, reactor coolant (pressurized or depressurized) or suppression pool water, depending on the sampling line take-off location.

7. Containment Atmospheric Control System

The recombiner system and associated H_2-O_2 analyzer lines would recirculate primary containment gas after an accident in order to keep hydrogen and oxygen concentrations at acceptable levels.

8. SGTS and RERS

The SGTS and RERS would collect airborne activity in the secondary containment following an accident. Radioactivity would be collected on the filters and charcoal beds in these systems.

9. Containment

The free volume of the primary containment is assumed to initially contain large amounts of postaccident activity. These sources, as well as those assumed for the suppression pool, are described below. Shine through the drywell and wetwell walls would cause a negligible increase to the secondary containment airborne and piping doses, and therefore was not included in this review.

10. MSIV Leakage Alternate Drain Pathway

Following the accident, the MSIV Leakage Alternate Drain Pathway will be aligned. The sources associated with this pathway are discussed below. Shine through the turbine condenser shield wall is considered negligible and therefore, was not included in this review.

D. Source Release Fractions

The following release fractions were used as a basis for determining the concentrations for the radiation and shielding review:

Source A:	Containment atmosphere:	100% noble gases, 25% halogens
Source B:	Suppression pool liquid:	50% halogens, 1% solids
Source C:	Reactor steam:	100% noble gases, 25% halogens
Source D:	Pressurized reactor coolant:	100% noble gases, 50% halogens, 1% solids

These release fractions were applied to the total curies available for the particular chemical species (i.e., noble gas, halogen, or solid) for an equilibrium fission product inventory for a light-water reactor core.

E. Source Term Models

The assumptions used for release fractions for the radiation and shielding design review are outlined above. These release fractions are, however, only the first step in modeling the source terms for the activity concentrations in the systems under review. The decay time and dilution volume also affect the rationale for the selection of values for these parameters.

1. Decay Time

For conservatism, no decay time credit was taken for the radioactive decay that might occur before fission products would be transported to the various systems.

2. Dilution Volume

The volume used for dilution is important, affecting the calculations of dose rate in a linear fashion. The following dilution volumes were used with the release fractions listed above in Section D to arrive at the final source terms for the shielding reviews.

Source A: Drywell and suppression pool free air volumes.

Source B: The volume of the RCS (based on reactor coolant density at the operating temperature and pressure) plus the suppression pool water volume.

Source C: The total reactor system steam volume.

Source D: The volume of the RCS.

3. Contained Sources and Drywell and Secondary Containment Airborne Sources

In defining the contained sources, accident operating modes were assumed for each system. In defining the limits of the connected piping subject to contamination listed below, normally shut valves were assumed to remain shut.

- CS system - Source B
- HPCI system

  Liquid - Source B

  Steam - Source C (with credit for steam specific activity reduction due to turbine operation).

- RCIC system

  Liquid - Source B
  Steam - Source C (with credit for steam specific activity reduction due to turbine operation).

- RHR system - Source B (all modes)
- Postaccident Sampling Lines

  Gas sample lines - Source A
  Liquid sample lines - Source D

- Containment Atmospheric Control (Recombiner) System - Source A (Drywell free volume only)
- Drywell - Source A
- MSIV Leakage Alternate Drain Pathway – Source C
- SGTS, RERS, and Secondary Containment Activity

The following major assumptions were used to calculate the secondary containment airborne radiation doses and the radiation doses for the SGTS filters and the RERS filters.

a. 100% of the noble gases and 25% of the halogens are available for leakage into the secondary containment.

b. The primary to secondary containment leak rate is 0.5% per day.

c. Airborne activity in the secondary containment is confined to spaces below the refueling floor for normal reactor enclosure/refueling area HVAC alignment. Other alignments have been evaluated to provide additional flexibility during refueling operations.

d. The RERS flow rate is two secondary containment air changes per hour.

e. The SGTS flow rate is one air change per day. (For equipment qualification of equipment in the reactor enclosure, the secondary containment airborne doses and RERS filter doses were conservatively based on an SGTS flow rate of one-half air change per day. This results in a longer holdup time and therefore higher doses. For equipment qualification of the SGTS and equipment in the vicinity, an SGTS flow of one air change per day was used.)

f. The RERS charcoal filter is 95% efficient with respect to halogens.

g. The SGTS charcoal filter is 100% efficient with respect to halogens for filter loading.

h. The activity inventory in the core was based on 1000 days burnup and daughter product formation was not considered. These assumptions, which have off-setting effects, were necessitated by limitations in the computer code used to treat the transport of activity from primary to secondary containment.

i. The capacities of the RERS and SGTS filters are sufficient to sustain cleanup for the duration of the accident.

j. Deleted

4. Airborne Sources for Vital Areas

All the vital areas and access paths are located in the turbine enclosure, radwaste enclosure, control structure, administration building, diesel generator enclosure, TSC, and yard areas. The transport pathway of the airborne sources in these areas consists of leakage from the primary containment to the reactor enclosure, and discharge to the environment via the RERS and the SGTS. The airborne activity discharged then re-enters the buildings through the ventilation intake systems after dilution within the building wake cavity.

The assumptions used in calculating the released airborne activity are the same as those listed in Section 3 above the secondary containment except that an SGTS flow rate of one air change per day and the technical specification minimum filter efficiencies are used to maximize the activity released (i.e. RERS is 95%, and SGTS is 99%, efficient). Also, an assumed 5 gpm systems leakage (at suppression pool activity concentration) to the secondary containment is included in the analysis.

The atmospheric dispersion factors (X/Q), along with their calculation basis, are given in Section 15.10 Section 15.10.2.2 “Control Room Dose Module” includes the main control room, HVAC panels, and the north stack instrument room. The X/Q's for the other vital areas are analyzed using the modified Halitsky X/Q methodology. This methodology is discussed below.

J. Halitsky's efforts summarized in Reference 1.13-1 present the basic equation as follows:

$$X/Q = K/A\bar{u}$$

where:

A = cross-sectional area, M^2 orthogonal to u

▫ = wind speed, m/s

K = isopleth (Concentration coefficient - dimensionless)

It is found in many cases that the above Halitsky equation still provides a reasonable estimate of X/Q. Several correction factors can be applied to this equation to account for situation and plant specific features, such as:

- Stream line flows are used in most wind tunnel tests
- Release points are generally much higher than 10 meters above ground
- Null wind velocity is observed at certain periods of time
- Isothermal temperatures are used in wind tunnel tests
- Buoyancy and jet momentum effects are ignored
- Typical 1 hr field tests account for plume meander effects while 3-5 minute wind tunnel tests do not.

A modified Halitsky X/Q methodology was thus formulated and is presented below.

$$X/Q = \frac{K}{\bar{\bar{u}}} \bullet f_1 \bullet f_2 \bullet f_3 \bullet f_4 \bullet f_5 \bullet f_6 \text{ (sec/m}^3\text{)}$$

As a test of the modified Halitsky method, calculated values of X/Q, without using factors f_4 and f_5 due to their uncertainty, were compared to the 1 hour field test X/Q data from Rancho Seco (Reference 1.13-3). Only one X/Q was found to be higher than the calculated value. This was due to an external wake influence caused by wind channeling between the nearby cooling towers. The wind channeling prevented the normal wake turbulence and variation effects over time, which normally spread the plume over a wide area. In most cases the modified Halitsky X/Q was found to be a conservative estimate of the measured X/Q; in some cases it was significantly higher.

The choice of K factors and the suggested modifying factors f_1, f_2, etc, are discussed below.

<u>K factors</u>: The choice of an appropriate K factor from the wind tunnel test data is critical for the X/Q estimate to be valid. Halitsky, in Reference 1.13-1, has several sets of K isopleths for round topped containments (PWRs) and block buildings (BWRs). Multiple building complexes must be simulated by single equivalent structures. The effluent velocity to wind speed ratio of approximately 1 is valid for most power plant systems. Various angles of wind incidence are shown to account for vortexing which could result in worse conditions than a wind normal to the building face. K factors should be estimated for various combinations of wind incidence angle and the appropriate effective building cross-sectional area causing the wake (not just the containment area) to determine the peak value as was done by Walker (Reference 1.13-4).

<u>Wind speed ($\bar{u}$)</u>: Halitsky's K values are based on wind speeds measured at the top of the containment or building. Therefore, the Reference 1.13-2 five percentile wind speed at a 10 meter height should be adjusted to the actual speed at the top of containment or release point. The five percentile wind speed is adjusted using the formulation presented by Wilson (Reference 1.13-5) as follows:

$$\bar{u}_T = \bar{u}\left(\frac{Z}{Z_{Ref}}\right)$$

where:

$\bar{u}_T$ = wind speed at height Z

Z_{Ref} = 10 meters (five percentile wind speed reference height)

<u>Wind speed change factor (f_1), and Wind direction change factor (f_2)</u>: The factor supplied from Reference 1.13-2, shown below, were used.

Time Periods	f_1	f_2
0 - 8 hrs	1	1
8 - 24 hrs	.67	.88

24 - 96 hrs	.50	.75
96 - 720 hrs	.33	.50
720 hrs & on	.25	.33

Wind turbulence effect (f_3): Wilson (Reference 1.13-5) and field tests confirm Halitsky's statement that his K isopleths are a factor of 5 to 10 too conservative due to not accounting for random fluctuations of the wind approaching the building. Therefore, a factor of 0.2 was used for f_3.

Elevated release effect (f_4): Bouwmeester (Reference 1.13-6) indicates that there are up to 10 null wind speed conditions during an hour of data collection. During these periods the effects of jet momentum, plume rise, and buoyancy would result in the radioactive effluent being discharged above the effective wake boundary and thus not entering the wake cavity. A reduction factor of 1 was used.

Time average effects (f_5): Wind speed variations and wind direction meandering effects are not modeled in wind tunnel tests to account for this effect. Reference 1.13-6 indicates the use of the following equation:

$$C_p = C_m \left(\frac{t_p}{t_m}\right)^{-1/2}$$

where:

C_p	=	prototype concentration
C_m	=	model concentration
t_p	=	prototype sampling time
t_m	=	model equivalent sampling time

Normal wind tunnel data is taken for 3 to 10 minute samples. Thus, for a 1 hour field test, C_p = .22 to .41 C_m and for an 8 hour field test, C_p = .08 to .14 C_m. A value of 0.5 was conservatively assumed for f_5.

Adjustment to top of stack (f_6): To account for wind speed at the top of the stack instead of the Reference 1.13-2 five percentile wind speed at 10 meters height, the factor $f_6 = \bar{u} / \bar{u}_r$ was included. The f_6 value equals 0.66.

The resultant X/Q (sec/m^3) calculated for each of the vital areas except for the main control room, HVAC panels and north stack instrument room (control room X/Q calculated in Section 15.10 was used) are thus shown in Table 1.13-7.

For the MSIV Leakage Alternate Drain Pathway, the F_6 factor is 1.0, since the release point is not an elevated release point.

F. Radiation Dose Calculation

1. Primary and Secondary Containment Doses

The sources described above in Section E were used to estimate doses from the systems included in the radiation and shielding design review. No vital areas are located in the primary or secondary containments, thus the doses described in this section were used for equipment qualification purposes only.

Both gamma and beta post-LOCA doses were calculated for the primary containment. The doses were calculated by assuming that 100% of the core noble gas inventory and 50% of the core halogen inventory are released. These source terms are consistent with those specified in NUREG-0588 and NUREG-0737.

The primary containment airborne dose calculations assumed that 50% of the 50% (i.e. 25%) halogen release from the core plates out instantaneously, as assumed implicitly in Regulatory Guide 1.3 (Rev 2). The airborne doses were calculated assuming source terms diluted by the primary containment (drywell and wetwell) free volume. These assumptions are consistent with those specified in NUREG-0737.

The beta doses and dose rates for qualification of equipment were calculated assuming an infinite cloud geometry. The beta doses and dose rates for qualification of coatings were calculated assuming a semi-infinite cloud geometry.

For components inside primary containment the total integrated gamma doses were calculated by adding the post-LOCA primary containment gamma cloud dose to the 40 year normal operating dose. Dose distance relationships were not used to reduce post-LOCA doses inside primary containment.

Both gamma and beta post-LOCA doses were also calculated for the secondary containment, based on the source terms described above in Section E. For compartments inside the secondary containment, the post-LOCA gamma radiation levels were conservatively determined by adding the maximum piping contact dose in that compartment to the secondary containment gamma cloud dose. The total integrated gamma dose was then determined by adding the post-LOCA integrated dose to the 40 year normal operating integrated dose. The equipment qualification levels for all safety-related electrical components were compared to the applicable calculated dose. For those components initially listed as inadequately qualified, more detailed

calculations were performed, taking into account dose/distance relationships in order to determine more realistic doses. A set of dose/distance curves for each system was developed as part of this effort.

2. Doses in Other Plant Areas for Equipment Qualification

Doses for specified areas outside the secondary containment were also calculated as described below, for equipment qualification purposes. For the SGTS equipment compartment, the post-LOCA gamma dose is the contact dose of the SGTS filters. For the remaining areas, the post-LOCA gamma doses were determined by adding the cloud, filter and piping shine doses from adjacent compartments and the control structure cloud dose, as applicable. These post-LOCA doses were added to the normal operating integrated dose to determine the total integrated gamma doses. Beta doses outside secondary containment would be negligible for equipment qualification purposes, and therefore they were not calculated.

3. Vital Area and Access Path Doses

Calculations were performed to determine airborne and shine doses from the sources described above in Section E to the vital areas and access paths. These doses were used to determine personnel exposures, using occupancy factors as described below in Section G. For radiation doses due to direct shine, credit was taken for attenuation through the walls and due to distance. For airborne doses, both gamma and beta contributions were included. In the access path airborne dose calculations for the yard area routes, the most conservative X/Q bounding that route was used.

G. Personnel Exposure Limits

The general basis for personnel radiation exposure guidelines was GDC 19. The following additional radiation limit guidelines were used to evaluate occupancy and accessibility of plant vital areas and access paths.

Radiation Exposure Guidelines

Occupancy	Dose Objective
Continuous	≤ Rem for duration
Infrequent	≤ Rem for all activities
Accessway	≤ 10 Rem/hr

These dose objectives are for personnel access only.

Emergency Response Procedures specify the criteria for radiological habitability monitoring to insure the dose objectives are not exceeded. Based on the results of the habitability monitoring personnel in the affected areas may be instructed to don protective devices or limit stay times to maintain the dose objectives.

The dose rate received by personnel in vital areas of continuous occupancy should be <15 mrem/h (average over 30 days). The doses for these areas were determined using the control room occupancy factors contained in SRP 6.4, as discussed in NUREG-0737, i.e., 1.0 for 0-1 day; 0.6 for 1-4 days; and 0.4 for over 4 days.

The dose received by personnel in an infrequent occupancy of vital areas and access paths is determined by taking into account the frequency and duration of the activities anticipated for that area, and is consistent with GDC 19 limits. Average area dose rates are used to determine personnel exposure, although local hot spots may exist.

H. Results of Dose Calculations

1. Environmental Qualification of Equipment

Normal operating radiation doses and conservative post-LOCA gamma and beta doses are provided in the Equipment Qualification Report and its references for all areas containing safety-related equipment. Equipment was reviewed against these doses or, if necessary, against reduced doses calculated as described above in Section F.1. The results of the review of equipment are provided in the EQR.

2. Personnel Access

The reactor enclosure and refueling floor will be inaccessible after a design basis LOCA. However, this does not present a problem since they do not contain any vital areas requiring operator access. The non-LOCA reactor enclosure will be accessible.

Doses to the vital areas described above in Section B from the sources described above in Section E are provided in Table 1.13-1. The dose objective of Table 1.13-1 are not used to limit access in the event of an accident.

Dose rates for vital area access paths are provided in Table 1.13-2. These access paths are given in Table 1.13-5.

The airborne and direct shine doses must be added together to show the total dose to personnel in the vital areas and access paths.

Peak shine dose rates are provided in Table 1.13-1 along with the integrated doses. The dose rate at any given time for a vital area can be estimated by multiplying the peak dose rate by an appropriate factor which can be determined by using the curves in Figures 1.13-1 and 1.13-2.

Potential problem areas that were identified in the design review of plant shielding are listed in Table 1.13-3, along with the solutions that will be followed for these areas.

I. Conclusion

Areas and safety-related equipment vital for postaccident occupancy or operation were identified, and postaccident doses were calculated in accordance with the requirements of NUREG-0737. Also in Table 1.13-3, potential problem areas were identified, and solutions for these problems were determined. No additional shielding is required as a result of this study.

• II.B.3 POST ACCIDENT SAMPLING

The information in the position and response is historical and represents the original plant design requirements based on source terms consistent with TID-14844. The application of Alternative Source Terms (AST) per Regulatory Guide 1.183 has resulted in the re-assessment of control room and off-site radiological consequences from design basis accidents. See UFSAR Chapter 15 for additional information.

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 18¾ rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential

Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," or Regulatory Guide 1.4 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactor" release of fission products. If the review indicates that personnel could not promptly and safely obtain 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 and isotopes which indicate fuel melting. The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or Regulatory Guide 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 Regulatory Guide 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).

<u>Clarification</u>

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13, 1979, October 30, 1979, September 5, 1980 and October 31, 1980 clarification letters.

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

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

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

   (b) Hydrogen levels in the containment atmosphere;

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

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

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

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

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

(6) The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding GDC 19 (i.e., 5 rem whole body, 75 rem extremities).

(7) If inline monitoring is used for any sampling and analytical capability specified herein, the applicant 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.

(8) The applicant's radiological and chemical sample analysis capability shall include provisions to:

(a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 1.3 or Regulatory Guide 1.4 and Regulatory Guide 1.7, "Control of Combustible Gas Concentration in Containment Following a Loss-of-Coolant Accident." 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.

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

(9) Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the RCS.

(10) In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:

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

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

(11) If gas chromatography is used for reactor coolant analysis, special provisions (e.g., pressure relief and purging) shall be provided to prevent high pressure argon from entering the reactor coolant.

(12) Applicants should provide a description of the implementation of the position and clarification including pipe and instrumentation drawings, together with either (a) a summary description of procedures for sample collection, sample transfer or transport, and sample analysis, or (b) copies of procedures for sample collection, sample transfer or transport, and sample analysis, in accordance with the proposed review schedule but in no case less than 4 months prior to the issuance of an operating license. A postimplementation review will be performed.

Response

Provisions for postaccident reactor coolant and containment atmosphere sampling and analysis are described in Sections 6.2.5, 7.5.1 and 11.5.5.

Limerick license amendment numbers 166/129 approved the elimination of the requirement to have and maintain the Post Accident Sampling System. The following items were committed to as part of the license amendment numbers 166/129.

1. Limerick has developed contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, suppression pool, and containment atmosphere. The contingency plans are contained in the Limerick chemistry procedures. Establishment of contingency plans is considered a regulatory commitment.

2. The capability for classifying fuel damage events at the Alert level threshold has been established at a level of core damage associated with radioactivity levels of 300 micro-curies/gm dose equivalent iodine in the primary coolant system. This capability is described in Limerick's emergency plans and emergency plan implementing procedures. The capability for classifying fuel damage is considered a regulatory commitment.

3. Limerick has established the capability to monitor radioactive iodines that have been released offsite to the environs. This capability is described in the emergency plans and emergency plan implementing procedures. The capability to monitor radioactive iodines is considered a regulatory commitment.

The following information contained in the UFSAR regarding the regulatory requirements for post accident sampling is retained for historical purposes.

A grab sample system designed by GE is provided. Radiological spectrum and chemical analysis capabilities have been established to ensure that the appropriate analyses can be performed in a timely manner.

Shielding requirements and source terms used will be consistent with those used for the Design Review of Plant Shielding, discussed under Item no. II.B.2.

- II.B.4 TRAINING FOR MITIGATING CORE DAMAGE

Position

We require that the applicant develop a program to ensure that all operating personnel are trained in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. They must then implement the training program.

Clarification

STAs and operating personnel from the plant manager through the operations chain to the licensed operators shall receive this training. The training program shall include the following topics:

(1) Incore Instrumentation

(a) Use of fixed or movable incore detectors to determine extent of core damage and geometry changes.

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

(2) Excore Nuclear Instrumentation

(a) Use of excore nuclear instrumentation for determination of void formation; void location basis for excore nuclear instrumentation response as a function of core temperatures and density changes.

(3) Vital Instrumentation

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

(b) Alternative methods for measuring flows, pressures, levels, and temperatures.

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

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

(iii) Determination of other RCS parameters if the primary method of measurement has failed.

(4) Primary Chemistry

(a) Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leak-tight systems.

(b) Expected isotopic breakdown for core damage; for clad damage.

(c) Corrosion effects of extended immersion in primary water; time to failure.

(5) Radiation Monitoring

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

(b) Methods of determining dose rate inside containment from measurements taken outside containment.

(6) Gas Generation

(a) Methods of hydrogen generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of noncondensables.

(b) Hydrogen flammability and explosive limit; sources of oxygen in containment or RCS.

Managers and technicians in the instrumentation and control, health physics, and chemistry departments shall receive training commensurate with their responsibilities.

Response

The lesson plan for the training program for mitigating core damage was developed prior to fuel loading, and training completed prior to full power operation. The course outline is presented below.

Core Cooling Mechanics
Alternate methods of core cooling
Core spray and core flooding
Heat removal paths
Boron precipitation
Fuel cladding quenching
Limiting core conditions
Steam and water cooling

Potentially Damaging Operating Conditions
Vulnerable plant operating conditions

Core cooling with systems unavailable

Gas/Steam Binding Affecting Core Cooling
Sources of gas/steam vapor
Symptoms/effects of gas/steam binding
Recognizing Core Damage
Data collection, instrumentation, and systems
Fuel/clad behavior
Reporting requirements

Core Recriticality
Reactor Shutdown margin
Maintaining subcriticality
SLCS
Instrumentation response

Hydrogen Hazards During Accidents
Sources of hydrogen and oxygen
Hazardous concentrations and reduction
Gas venting

Monitoring Critical Parameters During Accident Conditions
Parameter identification
Instrumentation reliability, accuracy, and failure

Radiation Hazards and Radiation Monitor Response
Emergency plan implementation
High radiation areas
Sampling
Radiation monitor response and failure

Criteria for Operation and Cooling Mode Selection
Core cooling procedures
Core cooling equipment and methods

STAs and operating personnel from the Station Superintendent through the operations chain including the licensed operators receive this training.

Other plant managerial personnel and technicians in the instrumentation and control, health physics, and chemistry groups also receive training commensurate with their responsibilities during accident conditions.

- II.D.1 RELIEF AND SAFETY VALVE TEST REQUIREMENTS

Position

PWR and BWR licensees and applicants shall conduct testing to qualify the RCS relief and safety valves under expected operating conditions for design basis transients and accidents.

Clarification

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

(1) Performance Testing of Relief and Safety Valves - The following information must be provided in report form:

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

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

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

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

(3) ATWS Testing - Although ATWS testing need not be completed by July 1, 1981, the test facility should be designed to accommodate ATWS conditions of approximately 3200 to 3500 (Service Level C pressure limit) pounds per square inch and 700°F with sufficient capacity to enable testing of relief and safety valves of the size and type used on operating PWRs.

<u>Response</u>

The licensee participated in the BWROG program to test SRVs. The test program has been successfully completed and is described in Reference 1.13-8. The applicability of the test results to the LGS valves is described in appendix A of Reference 1.13-8.

An engineering evaluation was done to identify the expected operating conditions for SRVs during design basis transients and accidents. This evaluation identified one event for which testing was appropriate. This event, the alternate shutdown cooling mode, is an anticipated operating condition that has been considered in the design analysis (Section 5.4.7.5).

The test results documented in the topical report verify the adequacy of the LGS valve operation and integrity under the expected discharge conditions. The loads on the valve and piping induced by the liquid discharge were shown to be lower than the high pressure steam discharge loads for which the system is designed. The test results also provide flow capacity information to show that sufficient shutdown cooling flow is provided through one or two valves, dependent on reactor and system conditions. Clarification Items (2) and (3) are not applicable to BWRs.

- II.D.3 RELIEF AND SAFETY VALVE POSITION INDICATION

Position

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

Clarification

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

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

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

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

(5) The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with Commission Order of May 23, 1980 (CLI-80-21).

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

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

(b) integration into emergency procedures,

(c) integration into operator training, and

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

Response

An acoustic monitoring system that meets the requirements of NUREG-0737 and Regulatory Guide 1.97 is provided for LGS (Sections 7.6.1.5 and 7.6.2.5). The system is designed to the following general requirements:

a. A reliable, single channel, direct indication system is provided.

b. The individual valve position (OPEN/CLOSED) is displayed in the control room. In conjunction with this indication, a third indication signifies that the individual valve has been open. These lights are located above each SRV control switch. An alarm is provided in the control room to annunciate when any valve is open.

c. The position indications are powered from a highly reliable non-Class 1E power source (Section 8.3.1.1.1).

   A diverse means of valve position indication as specified in the EOPs is provided by the redundant safety-grade suppression pool temperature monitoring system. This is powered from a Class 1E power source.

d) All valve position system components are seismically qualified except for the power supply.

e) All valve position system components located in a potentially harsh environment qualified for a LOCA environment.

f) A human factors analysis was performed to integrate this new information into the control room. The individual OPEN/CLOSED/WAS OPEN indication is located above the SRV control switch.

The WAS OPEN indication was added to aid the operator in determining which valve has opened when a relief valve instantaneously opens on high pressure and closes immediately. This indication is also used to aid the operator in sequencing the relief valves when the reactor is manually depressurized.

Additional human factors aspects were considered during the CRDR required by Item I.D.1.

- II.E.1.1 AUXILIARY FEEDWATER SYSTEM EVALUATION

Response

These requirements are not applicable to BWRs.

- II.E 1.2 AUXILIARY FEEDWATER SYSTEM INITIATION AND FLOW

Response

This requirement is not applicable to BWRs.

- II.E.3.1 EMERGENCY POWER FOR PRESSURIZER HEATERS

Position

Consistent with satisfying the requirements of GDC 10, 14, 15, 17, and 20 for the event of LOOP, the following positions shall be implemented.

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

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

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

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

Clarification

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

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

(3) The power sources need not necessarily have the capacity to provide power to the heaters concurrently with the loads required for LOCA.

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

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

(a) which ESF loads may be appropriately shed for a given situation;

(b) reset of the safety injection actuation signal to permit the operation of the heaters; and

(c) instrumentation and criteria for operator use to prevent overloading a diesel generator.

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

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

Response

This requirement is applicable to PWRs only. Because the BWR operates in all modes with both liquid and steam in the RPV, saturation conditions are always maintained irrespective of system pressure. There is no need for emergency power to maintain natural circulation or to keep the system pressurized.

The LGS power-operated MSRVs can be actuated using emergency power and have no block valves. They are described in Section 5.2.2. They are nitrogen-operated valves, with their normal gas supply coming from the PCIG compressors, which are described in Section 9.3.1.3. Standby ac power is available to the PCIG compressors following a LOOP.

The MSRVs are provided with gas accumulators described in Section 5.2.2.4, for reliable short-term operation without PCIG system operation. A safety-grade gas bottle supply system, described in Section 9.3.1.3, is available for long-term MSRV operation.

Safety-grade reactor vessel level indication is provided in the control room in accordance with Regulatory Guide 1.97 (Rev 2). Additional information is provided in Section 7.5.

- II.E.4.1 DEDICATED HYDROGEN CONTROL PENETRATIONS

Position

Plants using external recombiners or purge systems for postaccident 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 GDC 54 and 56 and that are sized to satisfy the flow requirements of the recombiner or purge system.

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

Clarification

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

(2) The dedicated penetration or the combined single failure proof alternative shall be sized such that the flow requirements for the use of the recombiner or purge system are satisfied. The design shall be based on 10CFR50.44 requirements.

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

(4) Licensees that rely on purge systems as the primary means for controlling combustible gases following a LOCA should be aware of the positions taken in Reference 1.13-9. 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.)

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

Response

The containment hydrogen recombiner system, described in Sections 6.2.5 and 9.4.5, is used for postaccident combustible gas control. The recombiners are permanently installed external to the primary containment and are remotely operated from the control room. The design of the containment penetrations associated with the hydrogen recombiner system is single failure proof for containment isolation purposes during system operation and single failure proof for operation of the recombiner system.

LGS complies with each of the points of clarification as described below.

(1) The containment isolation arrangement uses a combined type of design which is single failure proof as permitted by this clarification item. The hydrogen recombiner supply and return lines connect to the high volume purge lines outside the primary containment. Each high volume purge line is provided with redundant, normally closed isolation valves installed in series outboard of the connection point with the hydrogen recombiner lines. This redundancy ensures that isolation of the high volume purge lines remains single failure proof during operation of the recombiners. Each supply and return line for the hydrogen recombiners is provided with two, normally closed containment isolation valves in series. Because two valves in series are provided, the failure of an isolation valve in the open position would not jeopardize containment integrity. The provision of two redundant hydrogen recombiner packages ensures that the recombination function can be performed in the event of a failure of an isolation valve in the closed position.

(2) The recombiner supply and return lines have been sized such that the flow requirements of the recombiners are satisfied for the full range of possible containment pressures that may exist during the time period when the recombiners are required to operate.

(3) As discussed in Section 9.4.5.1.3, the hydrogen recombiner packages, their associated piping, and the containment isolation provisions for the recombiner lines and the containment purge lines are designed as safety-related.

(4) LGS does not rely on a purge system as the primary means for controlling combustible gases following a LOCA.

(5) LGS does not use a containment air dilution system for combustion gas control.

- II.E.4.2 CONTAINMENT ISOLATION DEPENDABILITY

Position

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

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

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

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

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

(6) Containment purge valves that do not satisfy the operability criteria set forth in BTP 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.

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

Clarification

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

(2) For postaccident situations, each nonessential penetration (except instrument lines) is required to have two isolation barriers in series that meet the requirements of GDC 54, 55, 56, and 57, as clarified by SRP 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 SRP Section 6.2.4, to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration must receive the diverse isolation signals.

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

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

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

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

(7) Sealed closed purge isolation valves should 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.

Response

A description of compliance with each Position and Clarification is provided below.

Position (1), Clarification (1)

The containment isolation system design has been reviewed for compliance with SRP 6.2.4 regarding diversity in the parameters sensed for the initiation of containment isolation. Section 6.2.4 and Table 6.2-17 identify all containment isolation signals provided. There are eleven valves classified as nonessential that do not receive diverse containment isolation signals.

Two valves on the feedwater lines (HV-109A, HV-109B) are normally closed and will be opened only for startup of the feedwater system before the control rods are withdrawn or when performing hydrostatic testing of the RPVs during unit shutdown.

The RCIC vacuum pump discharge line is provided with a stop-check valve (HV-F002) to prevent flow from the containment. A remote manually actuated motor operator ensures the long-term positive closure of the stop-check valve. This arrangement ensures that the essential RCIC pump-turbine will be ready to operate in the event of a reactor vessel isolation occurrence accompanied by loss of feedwater flow.

The recirculation pump cooling water supply and discharge isolation valves (HV-106, HV-107) and the drywell chilled water isolation valves (HV-122, HV-123, HV-128, HV-129) have provisions for remote manual isolation consistent with GDC 57. Closure of these isolation valves is undesirable unless the cooling water lines have failed.

The HPCI and RCIC steam supply line warmup valves (HV-F100, HV-F076, respectively) are provided with appropriate isolation signals to secure the line when system isolation is required. There is no adverse consequence associated with the valve opening or leaking while these systems are in operation.

The main steam drain line isolation valves (HV-F016, F019) are normally closed during power operation. They provide a path from the steam lines to the main condenser for removal of condensation during shutdown and startup periods and during periods of low load. The six automatic isolation signals provided for these valves are the same as those provided for the MSIVs.

The main steam and recirculation loop sample line isolation valves (HV-F084, F085 and HV-F019, F020, respectively) are typically open less than 1 hour per year during normal plant operations. The two isolation signals which are provided for these valves ensure their automatic closure before any fuel damage would occur for all anticipated periods of sample line use.

The RWCU supply line isolation valves (HV-F001, F004) are provided with the following signals to initiate automatic valve closure:

a. Reactor low water level

b. Line break in RWCU
   - high flow
   - heat exchanger high temperature
   - compartment high temperature

c. SLCS operation

These isolation signals are provided to protect the core in case of a possible break in the RWCU, to protect the ion exchange resin from damage due to high temperature, and to prevent the removal of boron by the ion exchange resin.

The RWCU system is described in Section 5.4.8. Closing times of the RWCU isolation valves have been chosen to prevent the reactor vessel water level from falling below the top of active fuel if a break were to occur in any of the RWCU lines. Diverse isolation signals are supplied to isolate the RWCU in the unlikely event of such a line break. The system is intentionally left in service whenever the above isolation signals are not activated to provide continuous purification of a portion of the recirculation flow.

Position (2), Clarification (3)

All systems penetrating containment have been evaluated and identified as either essential or nonessential. Table 6.2-17 provides the results of this evaluation for each line, and Table 6.2-27 provides the basis for the selection of essential/nonessential systems.

Position (3), Clarification (2)

Systems determined to be nonessential are provided with diverse, automatic isolation signals, except as described in the response to Position (1). Manual valves are sealed closed as discussed in Section 6.2.4.3.

Position (4), Clarifications (4), (5)

The control systems for automatic isolation valves are such that resetting the isolation signal will not result in the automatic reopening of these valves. The HPCI and RCIC steam line isolation valves are exceptions as discussed in Section 7.1.2.11. Ganged reopening of containment isolation valves is performed only where the operation of multiple valves is required for system operation. Sample inlet and return valve controls for the drywell radiation monitors and combustible gas analyzers are ganged as described in Sections 6.2.4.3.1.3.2.8 and 6.2.4.3.1.3.2.1. RECW and drywell chilled water valve controls are ganged as described in Sections 6.2.4.3.1.3.2.10 and 6.2.4.3.1.3.2.11.

Position (5), Clarification (6)

The setpoint for the drywell high pressure isolation signal is set at the minimum compatible with normal operation. Section 7.3.1.1.2.4.6 describes the selection of the drywell high pressure setpoint.

Position (6), Clarification (7)

Containment purge valves comply with BTP CSB 6-4 as discussed below and in Sections 9.4.5.1. Two purge isolation valves have closure times greater than 6 seconds (2"-HV-105 and 2"-HV-111 have closure times of 15 seconds). An analysis of the radiological consequences of a LOCA that occurs during purging was performed to justify the line size and the valve closure time used in the purge system. Using the assumptions of BTP CSB 6-4, the resulting doses were a small fraction of the 10CFR100 limits. For local leak rate tests, the leakage rate of the purge isolation valves, combined with the leakage rate for all other penetrations and valves subject to Type B and C tests will be less than 0.60 La, in accordance with 10CFR50, Appendix J.

Position (7)

The containment purge isolation valves isolate on receipt of any one of the following safety-related isolation signals:

a. high drywell pressure

b. reactor low water level

c. reactor enclosure high radiation

d. refueling floor high radiation

In addition to the safety-related isolation signals listed above, the containment purge and vent isolation valves (HV-114, 115, 104, 112, 123, 124, 135, 147, 121, 131, 109) will isolate on receipt of a nonsafety-related north stack effluent high radiation signal (Sections 6.2.4.3 and 11.5).

The setpoint of the isolation signal (approximately 4 μCi/cc) has been selected to ensure valve closure before offsite doses exceed EPA Protective Action Guide Level 2 limits (1 rem whole body/5 rem thyroid). Containment purging will not be undertaken during periods of power operation when this monitor is out of service unless a temporary replacement of equivalent sensitivity is used. Provisions are included in the Technical Specifications for periodic instrument calibrations and channel checks.

An analysis has been performed to demonstrate that the offsite doses that might result if a LOCA were to occur during purging operations would be less than both 10CFR100 and EPA Protection Action Guide limits. This analysis used the assumptions of SRP Section 6.2.4 and BTP CSB 6-4 and assumes a pre-existing spike that results in coolant activity levels in excess of Technical Specification limits. The analysis methodology was in accordance with Reference 1.13-10.

- II.F.1 ACCIDENT MONITORING INSTRUMENTATION

ATTACHMENT 1, Noble Gas Effluent Monitor

Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

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

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

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

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

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

(2) Integration into emergency procedures;

(3) Integration into operator training; and

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

Clarification

NUREG-0578, section 2.1.8b provided the basic requirements for this item. Letters dated September 27, 1979 and November 9, 1979, provided clarification and NUREG-0660, Item II.F.1 provided the action plan for additional accident monitoring instrumentation by noble gas effluent radiological monitor requirements. Additional clarification was provided by letters dated September 5, 1980 and October 31, 1980.

By summary clarification, the following guidelines were established:

(1) Applicants shall provide continuous monitoring of high level postaccident releases of radioactive noble gases from the plant. Gaseous effluent monitors shall meet requirements specified in Table 1.13-8. Typical plant effluent pathways to be monitored are also given in the table.

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

(3) Offline monitors are not required for the PWR secondary side main steam safety valve and 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.

(4) Instrumentation ranges shall overlap to cover the entire range of effluents from normal (ALARA) through accident conditions. The design description shall include the following:

    (a) System description, including:

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

        ii. monitoring locations (or points of sampling), including description of methods used to 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.

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

(5) Applicants should have available for review the final design description of the as-built system, including piping and instrument diagrams together with either (a) a description of procedures for system operation and calibration, or (b) copies of procedures for system operation and calibration. Changes to technical specifications will be required. Applicants will submit the above details in accordance with the proposed review schedule, but in no case less than 4 months prior to the issuance of an operating license. A postimplementation review will be performed.

The design description shall include the information provided in Table 1.13-8.

Until final implementation on January 1, 1982, all operating reactors must provide an interim method for quantifying high level releases which meet the requirements of the Table 1.13-8. This method is to serve only as a provisional fix until the accident monitoring instrumentation is installed, calibrated, tested and approved by January 1, 1982. Methods are to be developed to quantify release rates up to 10,000 Ci/sec for noble gases from all potential release points and any other areas that communicate directly with systems which may contain primary coolant or containment gases. Measurements/analysis capabilities of the effluents at the final release point (e.g., stack) should be such

that measurements of individual sources which contribute to the common release point may not be necessary. For noble gases, an acceptable method of meeting the intent of this requirement is to modify the existing monitoring system, such that portable high range survey instruments set in shielded collimators "see" small sections of the sampling lines. The applicant shall provide the following information on its method to quantify gaseous releases of radioactivity from the plant during an accident.

(a) An interim system/method description for noble gas effluents, including:

i. Instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique;

ii. monitoring/sampling locations, including methods to assure representative measurements and background radiation correction;

iii. a description of method to be employed to facilitate access to radiation readings. For January 1, 1981, control room readout is preferred; however, if impractical, in situ readings by an individual with verbal communication with the control room is acceptable based on (iv), below;

iv. capability to obtain radiation readings at least every 15 minutes during an accident; and

v. source of power to be used. If normal alternating current power is used, an alternate backup power supply should be provided. If direct current power is used, the source should be capable of providing continuous readout for 7 consecutive days.

(b) Procedures for conducting all aspects of the measurement/analysis, including:

i. procedures for minimizing occupational exposures;

ii. calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as function of time after shutdown;

iii. procedures for dissemination of information; and

iv. procedures for calibration.

Response

All reactor enclosure stack releases following an accident will be through the north stack. The wide range accident monitoring subsystem of the north stack effluent monitoring system provides continuous monitoring of postaccident releases of noble gases in accordance with the requirements of Table 1.13-8. The system is described in Sections 7.6 and 11.5.2.2.1, and its piping and instrumentation diagram is provided in drawing M-26. Control room displays provided for this system meet the requirements of Regulatory Guide 1.97 (Rev 2), and are described in Section 7.5. Table 1.13-9 outlines the requirements for an interim method for quantifying releases to be used by operating reactors and therefore is not applicable to LGS. Human factors aspects of TMI Item II.F.1 are considered part of the CRDR required by Item I.D.1.

ATTACHMENT 2, Sampling and Analysis of Plant Effluents

Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other regulatory guides, which will be promulgated in the near-term.

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.

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

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

(2) Integration into emergency procedures;

(3) Integration into operator training; and

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

Clarification

NUREG-0578, section 3.1.8b provided the basic requirements for this item. Letters dated September 27, 1979 and November 9, 1979, provided clarification, however, NUREG-0660 inadvertently omitted this requirement on the action plan for additional accident monitoring instrumentation by sampling and analysis of plant effluents. Additional clarification was provided by letters dated September 5, 1980 and October 31, 1980.

By summary clarification, the following guidelines were established:

(1) Applicants shall provide continuous sampling of plant gaseous effluent for postaccident releases of radioactive iodines and particulates to meet the requirements of Table 1.13-10. Applicants shall also provide onsite laboratory capabilities to analyze or measure these samples. This requirement should not be construed to prohibit design and development of radioiodine and particulate monitors to provide online sampling and analysis for the accident condition. If gross gamma radiation measurement techniques are used, then provisions shall be made to minimize noble gas interference.

(2) The shielding design basis is given in Table 1.13-10. 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 GDC 19 of 5 rem whole body exposure and 75 rem to the extremities during the duration of the accident.

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

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

(5) License applicants should have available for review the final design description of the as-built system, including P&IDs together with either (a) a description of procedures for system operation and calibration, or (b) copies of procedures for system operation and

calibration. Changes to technical specifications will be required. Applicants will submit the above details in accordance with proposed review schedule, but in no case less than 4 months prior to the issuance of an operating license. A postimplementation review will be performed.

Response

Sampling of plant gaseous effluents for postaccident releases of iodines and particulates is provided as part of the wide range accident monitoring subsystem of the north stack effluent radiation monitoring system described in Sections 7.6 and 11.5.2.2.1. The design of onsite laboratory facilities for analysis of these samples is described in Chapter 12. The design of the sampling media and sampling considerations are in conformance with Table 1.13-10. Human factors aspects of TMI Item II.F.1 are considered part of the CRDR required by Item I.D.1.

ATTACHMENT 3, Containment High Range Radiation Monitor

Position

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

Clarification

(1) Provide two radiation monitor systems in containment which are documented to meet the requirements of Table 1.13-11.

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

(3) The monitors shall be located in containment(s) in a manner 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.

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

(5) The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table 1.13-11. Monitors that use thick shielding to increase the

upper range will underestimate postaccident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gamma and are not acceptable.

Response

The primary containment post-LOCA radiation monitors described in Sections 7.1, 7.6.1, and 11.5.2.3.1 have a maximum range of 1 rad/hr to 10^8 rad/hr and are physically separated. They are designed and qualified to function in an accident environment.

Section 11.5.2.3.1 describes the degree of conformance with Item II.F.1 Attachment 3 and Table 1.13-11. Additional human factors aspects were considered during CRDR required by Item I.D.1.

ATTACHMENT 4, Containment Pressure Monitor

Position

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

Clarification

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

(2) Measurement and indication capability shall extend to 5 pounds per square inch absolute for subatmospheric containments.

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

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

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

Response

The containment pressure instrumentation is described in Section 7.5.1. The design and qualification of the instrumentation meets the guidelines of Regulatory Guide 1.97 (Rev 2) and Appendix B of NUREG-0737. The accuracy and maximum response time for the complete recording and indicating monitors conforms to the requirements of ANS 4.5 (1980) paragraphs 6.3.4 and 6.3.5, which is the referenced document of Regulatory Guide 1.97. Additional human factors aspects were considered during CRDR required by Item I.D.1.

ATTACHMENT 5, Containment Water Level Monitor

Position

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

Clarification

(1) The containment wide range water level indication channels shall meet the design and qualification criteria as outlined in Appendices B and C. The narrow range channel shall meet the requirements of Regulatory Guide 1.89.

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

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

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

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

Response

The existing suppression pool water level instrumentation and the compliance with the above position is described in Section 7.5.1 and meets the requirements of Regulatory Guide 1.97 (Rev 2). Additional human factors aspects were considered during CRDR required by Item I.D.1.

ATTACHMENT 6, Containment Hydrogen Monitor

Position

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

Clarification

(1) Design and qualification criteria are outlined in Appendix B.

(2) The continuous indication of hydrogen concentration is not required during normal operation. If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection.

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

Response

The existing hydrogen instrumentation and the compliance with the above position is described in Section 7.5.1 and meets the requirements of Regulatory Guide 1.97 (Rev 2). Additional human factors aspects were considered during CRDR required by Item I.D.1.

For Limerick Generating Station, continuous indication and recording will be functioning within 90 minutes of the initiation of safety injection. The basis for this 60 minute extension, is as follows: (1) information provided by the monitors is not immediately required following LOCA, as referenced in the Limerick Hydrogen and Oxygen Generation Analysis, Section 6.2.5.3 of the UFSAR. (2) it is appropriate to delay actions necessary to initiate hydrogen and oxygen monitoring until the immediate actions required of the operating crew, to assure that safety systems are functioning properly and critical safety functions are being accomplished, are complete. This is due to the relative safety significance of ensuring critical safety functions are being accomplished in the initial stages of the accident.

The hydrogen monitors have been downgraded to non-safety related as described in NRC Letter to Exelon Nuclear, Subject: "Limerick Generating Station, Units 1 and 2 Issuance of Amendment Re: Elimination of Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors (TAC Nos. MC2741 and MC2742)," dated 04/13/05. With the elimination of the Design Basis LOCA hydrogen release, hydrogen monitors are no longer required to mitigate DBAs and, therefore, do not meet the definition of safety related. However, because hydrogen monitors are required to diagnose the course of beyond DBAs, each licensee should verify that it has made a regulatory commitment to maintain a hydrogen monitoring system capable of diagnosing beyond DBAs.

The 0% - 10% hydrogen concentration range is discussed in NUREG-0737, from which the Attachment 6, Position and Clarification was obtained. See NUREG-0737 11.F 1, Attachment 6 for more information.

Measurement capability over the range of 0% to 10% hydrogen concentration is acceptable as the High Hydrogen Alarm setpoint (4%) falls within this range. Figures 6.2-42/43 show that the Drywell Hydrogen concentration will only exceed 10%, at least 8 days after a LOCA, with no hydrogen control. With recombiner operation at 150 scfm or a 150 scfm purge, hydrogen levels in the drywell will not exceed 4%. Figures 6.2-42/43 show that the Suppression Pool Hydrogen concentration will not exceed 4% for at least 30 days after a LOCA.

- 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 ICC. A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

Clarification

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

(2) The evaluation is to include reactor water level indication.

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

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

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

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

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

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

(7) All instrumentation in the final ICC system must be evaluated for conformance to Appendix B of NUREG-0737, "Clarification of TMI Action Plan Requirements," as clarified or modified by the provisions of items 8 and 9 that follow. This is a new requirement.

(8) If a computer is provided to process liquid level signals for display, seismic qualification is not required for the computer and associated hardware beyond the isolator or input buffer at a location accessible for maintenance following an accident. The single failure criteria of item 2, Appendix B, need not apply to the channel beyond the isolation device if it is designed to provide 99% availability with respect to functional capability for liquid level display. The display and associated hardware beyond the isolation device need not be Class 1E, but should be energized from a high reliability power source which is battery backed. The quality assurance provisions cited in Appendix B, item 5, need not apply to this portion of the instrumentation system. This is a new requirement.

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

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

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

(b) integration into emergency procedures,

(c) integration into operator training, and

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

Response

The design of LGS does not include the use of incore thermocouples for detection of ICC. The licensee endorses the position of the BWROG that there is no technical basis for requiring incore thermocouples in addition to the existing reactor water level instrumentation. A justification of the adequacy of the existing instrumentation to detect conditions of ICC is provided in section 2.3 of NEDO-24708A. Reactor water level instrumentation which is used to monitor ICC is described and reviewed for conformance to Regulatory Guide 1.97 (Rev 2) in Section 7.5.

• II.G.1 POWER SUPPLIES FOR PRESSURIZER RELIEF VALVES, BLOCK VALVES AND LEVEL INDICATORS

Position

Consistent with satisfying the requirements of GDC 10, 14, 15, 17, and 20 for the event of LOOP, the following positions shall be implemented:

Power supply for pressurizer relief and block valves and pressurizer level indicators -

(1) Motive and control components of the power-operated relief valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

(2) Motive and control components associated with the power-operated relief and block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

(3) Motive and control power connections to emergency buses for the power-operated relief valves and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.

(4) The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

Clarification

(1) Although the primary concern resulting from lessons learned from the accident at TMI is that the power-operated relief and block valves must be closable, the design should retain, to the extent practical, the capability to also open these valves.

(2) The motive and control power for the block valve should be supplied from an emergency power bus different from the source supplying the power-operated relief valves.

(3) Any changeover of the power-operated relief and block valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.

(4) For those designs in which instrument air is needed for operation, the electrical power supply should be required to have the capability to be manually connected to the emergency power sources.

Response

BWRs do not have pressurizer equipment. However, the LGS power-operated MSRVs can be actuated using emergency power and there are no block valves. They are described in Section 5.2.2. The relief valves are nitrogen-operated valves with their normal gas supply coming from the PCIG compressors which are described in Section 9.3.1.3. Standby ac power is available to the PCIG compressors following a LOOP.

The MSRVs are provided with gas accumulators described in Section 5.2.2.4 for reliable short-term operation without PCIG system operation. A safety-grade, gas supply system, described in Section 9.3.1.3, for long-term operation of the MSRVs is used for the ADS.

- II.K.1 IE BULLETINS ON MEASURES TO MITIGATE SMALL BREAK LOCAs AND LOSS OF FEEDWATER ACCIDENTS

- II.K.1.5 ASSURANCE OF PROPER ENGINEERED SAFETY FEATURES FUNCTIONING

Position

Review all safety-related valve positions, positioning requirements, and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also, review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during operational modes.

Response

Valve positioning requirements, positive controls, and test and maintenance procedures associated with ESF systems are addressed in station administrative procedures which have been generated based on the requirements of IE Bulletin 79-08 Item 6. MOVs in safety-related systems are normally maintained in a configuration such as to require the least number of valve automatic movements upon system actuation. The position of manual ECCS valves considered vital to system operability is controlled by the use and documentation of either locks, checklists, or independent verification. Surveillance test procedures for ESF systems include return-to-normal steps or checklists to ensure that the system is returned to service. Prior to fuel load, all ESF systems were confirmed to be aligned in accordance with approved checklists.

- II.K.1.10 REVIEW AND MODIFY, AS REQUIRED, PROCEDURES FOR REMOVING SAFETY-RELATED SYSTEMS FROM SERVICE (AND RESTORING TO SERVICE) TO ASSURE OPERABILITY STATUS IS KNOWN

Position

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known.

Response

An administrative procedure addressing the release from service and the return to service of safety-related equipment has been written to address the requirements of IE Bulletin 79-08 Item 8. This procedure, and surveillance test procedures, provide controls to ensure that the status of safety-related system operability is known prior to removal from service and return to service.

- II.K.1.17 TRIP PRESSURIZER LEVEL BISTABLE SO THAT LOW PRESSURE (RATHER THAN PRESSURIZER LOW PRESSURE AND PRESSURIZER LOW LEVEL COINDICENCE) WILL INITIATE SAFETY INJECTION

Position

Trip pressurizer level bistable so that low pressure (rather than pressurizer low pressure and pressurizer low level coincidence) will initiate safety injection.

Response

This requirement is not applicable to LGS which has GE-designed reactors.

- II.K.1.20 PROVIDE PROCEDURES AND TRAINING TO OPERATORS FOR PROMPT MANUAL REACTOR TRIP FOR LOSS OF FEEDWATER, TURBINE TRIP, MAIN STEAM LINE ISOLATION VALVE CLOSURE, LOSS OF OFFSITE POWER, LOSS OF STEAM GENERATOR LEVEL, AND LOW PRESSURIZER LEVEL

Position

Provide procedures and training to operators for prompt manual reactor trip for loss of feedwater, turbine trip, MSIV closure, LOOP, loss of steam generator level, and low pressurizer level.

Response

This requirement is not applicable to LGS.

- II.K.1.21 PROVIDE AUTOMATIC SAFETY-GRADE ANTICIPATORY REACTOR TRIP FOR LOSS OF FEEDWATER, TURBINE TRIP, OR SIGNIFICANT DECREASE IN STEAM GENERATOR LEVEL

Position

Provide automatic safety-grade anticipatory reactor trip for loss of feedwater, turbine trip, or significant decrease in steam generator level.

Response

This requirement is not applicable to LGS.

- 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.

Response

See Section 5.4.6 and 5.4.7 for discussion of the automatic and manual actions necessary for the proper functioning of heat removal systems when the main feedwater system is not available.

- II.K.1.23 DESCRIBE ALL USES AND TYPES OF REACTOR VESSEL LEVEL INDICATION FOR BOTH AUTOMATIC AND MANUAL INITIATION OF SAFETY SYSTEMS. DESCRIBE OTHER INSTRUMENTATION THAT MIGHT GIVE THE OPERATOR THE SAME INFORMATION ON PLANT STATUS

Position

Describe all uses and types of reactor vessel level indication for both automatic and manual initiation of safety systems. Describe other instrumentation that might give the operator the same information on plant status.

Response

Water level indication and measurement is discussed in Sections 7.2, 7.3, 7.5 and 7.7 and shown in drawing M-42 and Figure 7.7-1.

Automatic initiation of safety systems based on reactor water level is accomplished by the following instrument configurations:

1. RPS - Control rod scram is accomplished by four analog loops arranged in a one-out-of-two-twice logic such that the failure of any one switch or of any one set

of sensing lines will not defeat the safety action. This scheme uses four condensing chamber reference legs and two variable leg sensing lines.

2. PCRVICS - Group I Isolation is accomplished by four analog loops arranged in a one-out-of-two-twice logic such that the failure of any one switch or of any one set of sensing lines will not defeat the safety action. This scheme uses four condensing chamber reference legs and four variable leg sensing lines.

3. ECCS - Initiation of ADS, HPCI, LPCI, Core Spray and diesel generator start is accomplished by four analog loops arranged in a one-out-of-two-twice logic for each of the initiation trip units such that the failure of any one switch or any one set of sensing line will not defeat the safety action. This scheme uses the same sensing lines discussed in the PCRVICS above.

4. ATWS - Initiation of the ATWS functions is accomplished by four analog loops arranged in a one-out-of-two-twice logic such that failure of one switch or set of sensing lines will not defeat the safety action. This scheme uses two condensing chamber reference legs and two variable leg sensing lines. These are different variable lines from those used for the RPS.

   Manual initiation of the safety system based on water level may also be accomplished by use of the following indications: (note: all of the reactor water level instruments in this control room have a common reference zero.)

   a. Three narrow range level indicators and one wide range indicator are installed on the reactor console. The narrow range instruments also feed a signal to a recorder on the reactor console. This scheme employs three condensing chamber reference legs and two variable leg sensing lines. The wide range indicator scheme employs a separate condensing chamber reference leg and variable leg sensing line.

   b. Two postaccident range level indications, in response to Regulatory Guide 1.97, are installed on the ECCS panel. Each indication consist of overlapping wide range and fuel zone indicators. These schemes used two condensing chamber reference legs and four variable leg sensing lines.

   c. This indication is supplemented by the single channel upset range on the reactor panel and shutdown range on the recirculation and RWCU panel. Both of these schemes use the same condensing chamber reference leg and variable leg sensing line.

   d. In addition, all of these indications are fed into the ERFDS (SPDS) computer for display in a temperature compensated reactor water level display.

These instruments are augmented by the other parameters required by Regulatory Guide 1.97 (Rev 2) in the control room. These instruments are addressed in the EOPs to be used by the operator to assess plant conditions. The above water level and supplemental instrumentation was subjected to a human factors review and emergency procedure walk-through prior to fuel load.

- II.K.2 COMMISSION ORDERS ON BABCOCK & WILCOX PLANTS

Response

These requirements are not applicable to LGS.

- II.K.3 FINAL RECOMMENDATIONS OF B&O TASK FORCE

- II.K.3.1 INSTALLATION AND TESTING OF AUTOMATIC PORV ISOLATION SYSTEM

This section is not applicable to LGS.

- II.K.3.2 REPORT ON OVERALL SAFETY EFFECT OF PORV ISOLATION SYSTEM

This section is not applicable to LGS.

- II.K.3.3 FAILURE OF PORV OR SAFETY VALVE TO CLOSE

Position

Assure that any failure of a power-operated relief valve or safety valve to close will be reported to the NRC promptly. All challenges to the power-operated relief valves or safety valves should be documented in the annual report. This requirement is to be met before fuel load.

Response

Procedures for prompt notification of NRC include any failure of a SRV to close as one of the events requiring the shift manager to expeditiously notify the NRC.

- II.K.3.5 AUTOMATIC TRIP OF REACTOR COOLANT PUMPS DURING LOCA

This section is not applicable to LGS.

- II.K.3.7 EVALUATION OF PORV OPENING PROBABILITY DURING OVERPRESSURE TRANSIENT

This section is not applicable to LGS.

- II.K.3.9 PROPORTIONAL INTEGRAL DERIVATIVE CONTROLLER MODIFICATION

This section is not applicable to LGS.

- II.K.3.10 PROPOSED ANTICIPATORY TRIP MODIFICATION

This section is not applicable to LGS.

- II.K.3.11 JUSTIFICATION IN THE USE OF CERTAIN POWER-OPERATED RELIEF VALVES

Response

There are no power-operated relief valves at the LGS. The ADS system employs five SRVs to relieve high pressure in the reactor so that flow from LPCI and/or the CS systems enters the reactor in the event that RCIC and/or the HPCI system cannot maintain the reactor water level. See Sections 5.2.2 and 7.3 for further discussion.

- II.K.3.12 CONFIRM EXISTENCE OF ANTICIPATORY REACTOR TRIP UPON TURBINE TRIP

This section is not applicable to the LGS.

- II.K.3.13 SEPARATION OF HPCI AND RCIC SYSTEM INITIATION LEVELS - ANALYSIS AND IMPLEMENTATION

Position

Currently, the RCIC system and the 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 system 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 analysis.

Response

Analysis performed by the BWROG (NEDO-24951) has concluded that changing the initiation setpoint of HPCI/RCIC is unwarranted. The report recommended a modification to the RCIC circuitry to permit auto-restart of RCIC on low level after a high level trip. Therefore, modifications to the RCIC trip circuitry have been made to delete the high water level turbine trip and to apply this signal to the auto-close circuit of the steam supply valve. This provides automatic operation of the RCIC system to trip at high water level and auto-restart at low water level.

- II.K.3.15 MODIFY BREAK DETECTION LOGIC TO PREVENT SPURIOUS ISOLATION OF HPCI AND RCIC SYSTEMS

Position

The HPCI and 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.

Submit sufficient documentation to support a reasonable assurance finding by the NRC that the modifications, as implemented, have resulted in satisfying the concerns expressed in the previous requirements.

Response

The HPCI/RCIC steam line isolation logic has been modified to address the spurious isolation of these systems due to the pressure spike which accompanies startup of them. The modification consists of adding a time delay to the high flow trip logic of HPCI/RCIC. This prevents the instantaneous pressure spike from causing a system isolation.

- II.K.3.16 REDUCTION OF CHALLENGES AND FAILURES OF RELIEF VALVES - FEASIBILITY STUDY AND SYSTEM MODIFICATIONS

Position

The record of relief valve failures to close for all 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 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:

(1) Additional anticipatory scram on loss of feedwater

(2) Revised relief valve actuation setpoints

(3) Increased ECC flow

(4) Lower operating pressures

(5) Earlier initiation of ECCS

(6) Heat removal through emergency condensers

(7) Offset valve setpoints to open fewer valves per challenge

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

(9) Increasing the high steam line flow setpoint for MSIV closure

(10) Lowering the pressure setpoint for MSIV closure

(11) Reducing the testing frequency of the MSIVs

(12) More stringent valve leakage criteria

(13) Early removal of leaking valves.

An investigation of the feasibility and contraindications 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 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 SRVs 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 SRVs 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 contraindications of reducing the number of challenges to the valves by the various methods should be studied. Those changes which are shown to decrease the number of challenges without compromising the performance of the valves or other systems should be implemented.

Response

The licensee endorses the BWROG generic response to Item II.K.3.16 for LGS. This response is described in Reference 1.13-11. The following recommendations from this reference have been implemented at LGS in order to reduce the challenges to relief valves by approximately an order of magnitude:

1) Low water level isolation setpoint (see section 6.3.1.1.1 of Reference 1.13-11). The RPV water level isolation setpoint for MSIV closure is being lowered from Level 2 to Level 1 as part of the ATWS modifications for LGS.

2) Low-low set relief or equivalent manual actions (see section 6.3.1.3.1 of Reference 1.13-11). This recommendation ensures that by following the initial pressurization the pressure will be relieved by one valve alone, and the remaining SRVs will not experience any subsequent actuation. At LGS this will be accomplished manually as directed by the EOPs to manually open SRVs to terminate SRV cycling by reducing RPV pressure to below the lowest SRV safety lift setpoint, in accordance with guidance from the current BWROG EPGs.

3) Reduce MSIV testing frequency (see section 6.3.1.4.4 of Reference 1.13-11). A number of isolation events occur when the MSIV closure tests are being conducted. Reducing the MSIV test frequency would result in a reduction in the number of isolation events. Appropriate reductions have been made to the frequency of testing for the LGS MSIVs.

- II.K.3.17 REPORT ON OUTAGES OF ECCS SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

Position

Several components of the ECCS 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 ECCS. Licensees should submit a report detailing outage dates and lengths of outages for all ECCS for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Clarification

The present technical specifications contain limits on allowable outage times for ECCS and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECCS 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 ECCS for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) causes of the outage; (3) ECCS or components involved in the outage; and (4) corrective action taken. Tests 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 ECCS equipment, if needed.

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

Response

Starting from the date of commercial operations, for a period of five calendar years for each instance of ECCS unavailability because of component failure, maintenance outage (both forced or planned), or testing, the following information will be collected:

a. Outage date

b. Duration of outage

c. Cause of outage

d. ECCS or component involved

e. Corrective action taken

The above information will be assembled into a report, which will also include a discussion of any changes, proposed or implemented, deemed appropriate, to improve the availability of the ECCS equipment.

- II.K.3.18 MODIFICATION OF ADS LOGIC - FEASIBILITY FOR INCREASED DIVERSITY FOR SOME EVENT SEQUENCES

Position

The 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 HPCI or high pressure core spray flow exists and a low pressure ECCS is running. This logic would complement, not replace, the existing ADS actuation logic.

Response

Option 4, as outlined in the BWROG Generic Response to NUREG-0737 Item II.K.3.18, has been implemented prior to fuel load. Specifically, modifications were made to add a timer that would bypass the high drywell pressure permissive after a sustained low water level and to add an ADS manual inhibit switch.

- II.K.3.21 RESTART OF CORE SPRAY AND LPCI SYSTEMS

Position

The CS and 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 CS 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.

Part a

By January 1, 1981, each licensee shall submit proposed design modifications and supporting analysis which will contain sufficient information to support a reasonable assurance finding by the NRC that the above position is met. The documentation should include as a minimum:

(1) A discussion of the design with respect to the above paragraphs of IEEE 279 (1971);

(2) Support information including system design description, logic diagrams, electrical schematics, piping and instrument diagrams, test procedures and technical specifications

(3) Sufficient documentation to demonstrate that the system, as modified, would not degrade proper system functions.

Part b

Licensee to implement modifications at the next refueling outage following staff approval of the design unless this outage is scheduled within 6 months of the approval date. In this event, modifications will be completed during the following refueling outage.

Response

The licensee endorses the BWROG position for Item II.K.3.21 for LGS. This position was forwarded to the NRC by letter from D.B. Walters (BWROG) to D.G. Eisenhut (NRC) dated December 29, 1980. The conclusion of this position is that automation of the restart of LPCI and CS will result in a net decrease in safety because of the complexity of the logic required. Logic modifications to the LPCI and CS systems are therefore not warranted for LGS.

- II.K.3.22 AUTOMATIC SWITCH-OVER OF RCIC SYSTEM SUCTION - VERIFY PROCEDURES AND MODIFY DESIGN

Position

The RCIC system takes suction from the CST with manual switch-over to the suppression pool when the CST level is low. The switch-over should be made automatically. Until the automatic switch-over is implemented, licensees should verify that clear and cogent procedures exist for the manual switch-over of the RCIC system suction from the CST to the suppression pool.

Response

Modifications have been made to change the RCIC system suction valve logic to automatically switch suction from the CST to the suppression pool on low CST level.

- II.K.3.24 CONFIRM ADEQUACY OF SPACE COOLING FOR HPCI AND RCIC SYSTEMS

Position

Long-term operation of the RCIC and HPCI systems may require space cooling to maintain the pump-room temperatures within allowable limits. Applications should verify the acceptability of the consequences of a complete loss of ac power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite ac power to their support systems, including coolers, for at least 2 hours.

Response

At LGS, the HPCI and RCIC compartment unit coolers are powered by onsite emergency power and therefore continue to be available during a LOOP. The unit coolers are described in Section 9.4.2.2. The ESW pumps which provide flow to the coolers are also powered from onsite emergency power. Adequate space cooling is therefore assured during a LOOP. There are no other supporting systems that require offsite power such that operation of the HPCI and RCIC systems would be impaired if offsite power should be lost. The current LGS design is therefore acceptable.

- II.K.3.25 EFFECT OF LOSS OF AC 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 ac power for at least 2 hours. Adequacy of the seal design should be demonstrated. The results of the evaluation and proposed modifications are due by July 1, 1981. Modifications are to be implemented by January 1, 1982.

Clarification

The intent of this position is to prevent excessive loss of RCS inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be LOOP. If seal failure is the consequence of loss of cooling water to the reactor coolant pump seal coolers for 2 hours, due to LOOP, one acceptable solution would be to supply emergency power to the component cooling water pump.

Response

At LGS, two systems are available for cooling the recirculation pump seals: the RECW system and the recirculation pump seal purge system. Recirculation pump vendor test data has shown that if either one of these seal cooling systems is operating, seal temperatures will remain within acceptable limits and excessive seal deterioration is not expected to occur.

The primary cooling for the recirculation pump seals is provided by the RECW system which cools the reactor water that flows to the lower seal cavity. After a LOOP, the RECW pumps will be powered by onsite emergency power and will restart automatically. The service water system, which normally provides cooling water to the RECW heat exchangers, will not be available, but cooling water to the heat exchangers can be provided via manual realignment of the ESW system. If the RECW pumps do not restart or are unavailable for some other reason, the ESW can be manually routed directly to the recirculation pump seals for cooling by way of the RECW piping.

Backup cooling is provided by the recirculation pump seal purge system which injects cool water from the CRD system into the lower seal cavity. The CRD pumps are powered from the emergency diesels and can be manually restarted once onsite power is available. Therefore, the CRD pumps provide an alternate method for seal cooling during a LOOP. However, the ability to use CRD may be limited by the requirement to limit the RPV cooldown rate.

Even in the remote case where neither cooling source is reestablished and gross seal degradation occurs, the GE analysis performed under the direction of the BWROG has shown that the maximum coolant loss would be limited to 70 gpm per pump. This loss is small enough to be compensated for by normal or emergency reactor water level controls. It should be noted that since the initial licensing of the LGS Units, an improved seal design, prone to even less leakage in the event of failure, has been installed on the pumps.

Instrumentation for various parameters, including seal cavity pressure, seal staging and drain flows, drywell equipment drain sump pump flow and drywell floor drain sump pump flow is available to the operator to indicate potential seal failure. In addition, gross seal failure may lead to changes in drywell pressure, temperature, or radioactivity, all of which are monitored and recorded in the control room.

It is therefore concluded that a total loss of recirculation pump seal cooling is not a problem at LGS and modifications are not necessary.

- 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.

The applicant is to submit documentation by January 1, 1981 and implement action by April 1, 1981.

Response

All reactor vessel water level instruments are referenced to the bottom of the dryer skirt. Section 7.7.1.1.3.1.3 contains additional design information.

- II.K.3.28 VERIFY QUALIFICATION OF ACCUMULATORS ON ADS VALVES

Position

Safety analysis reports claim that air or nitrogen accumulators for the ADS valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated that the ECCS are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee and applicant should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee and applicant 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.

Response

The criteria and design basis for short-term ADS valve operation and accumulator capacity is given in Section 5.2.2.4.1. Long-term vessel depressurization capability for the alternate shutdown cooling flow path described in Section 5.4.7.5 is provided by supplying nitrogen to the ADS valves from the safety-grade system described in Section 9.3.1.3.

- II.K.3.30 REVISED SMALL BREAK LOCA METHODS TO SHOW COMPLIANCE WITH 10CFR50, APPENDIX K

Position

The analysis methods used by NSSS vendors and/or fuel suppliers for small break LOCA analysis for compliance with 10CFR50, Appendix K, should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

Clarification

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

As a result of the task force reviews, a number of concerns were identified regarding the adequacy of certain features of small break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each 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 10CFR50, Appendix K, 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 Bulletins and Orders Task Force reports for each LWR vendor. These concerns should be reviewed in total by each holder of an approved ECCS model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small break test series and LOFT Test (L3-1) and (L3-2). The staff believes that the present small break LOCA models can be both qualitatively and quantitatively assessed against these tests.

Other separate effects tests (e.g., Oak Ridge National Laboratory 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 submitted this information for staff review and approval.

Response

The response to the NRC small break model concerns was provided at a meeting between the NRC and GE on June 18, 1981. Information provided at this meeting showed that, based on the small break test results and sensitivity studies, the existing GE small break LOCA model satisfies the concerns of NUREG-0626 and is in compliance with 10CFR50, Appendix K. Therefore, the GE model is acceptable relative to the concerns of Item II.K.3.30, and no model changes need to be made to satisfy this item.

Documentation of the information provided at the June 18, 1981 meeting was provided via the letter from R.H. Buchholz (GE) to D.G. Eisenhut (NRC), dated June 26, 1981.

- II.K.3.31 PLANT SPECIFIC CALCULATIONS TO SHOW COMPLIANCE WITH 10CFR50.46

Position

Plant specific calculations using NRC approved models for small break LOCAs as described in II.K.3 item 30 to show compliance with 10CFR50.46 should be submitted for NRC approval by all licensees.

Calculations to be submitted by January 1, 1983 or 1 year after staff approval of LOCA analysis models, whichever is later (required only if model changes have been made).

Response

The small break LOCA calculations included in the LGS LOCA analysis are given in Section 6.3.3.7 and Table 6.3-5. The references listed in Section 6.3.6 describe the currently approved 10CFR50, Appendix K methodology used to perform these calculations. Compliance with 10CFR50.46 has previously been established for that methodology. As stated in the June 26, 1981, letter from R.H. Buchholz (GE) to D.G. Eisenhut (NRC), no model changes are needed to satisfy NUREG-0737 Item II.K.3.30; therefore, there is no need to revise the calculations given in Section 6.3.3.7.

The response provided above is historical. The original LOCA analysis has been replaced, and the applicable LOCA analysis is discussed in Section 6.3.3.7.

- II.K.3.44 EVALUATION OF ANTICIPATED TRANSIENTS WITH SINGLE FAILURE TO VERIFY NO FUEL 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 SORV should be included in this category. The results of the evaluation are due January 1, 1981.

Response

The BWROG transmitted a generic response to this requirement by letter dated December 29, 1980, from D.B. Waters (BWROG) to D.G. Eisenhut (NRC). This response contains an evaluation that states the worst case transient with single failure combination for BWR/4 plants is the loss of feedwater event with failure of the HPCI system. A SORV was also considered in addition to the HPCI failure. The results of these studies indicate that the core remains covered during the entire course of the transient either due to RCIC system operation or automatic or manual depressurization permitting low pressure inventory makeup. The operator action assumed in the analysis is to manually depressurize the vessel to permit low pressure injection.

By letter dated November 16, 1981, from J.S. Kemper (PECo) to D.G. Eisenhut (NRC), the licensee verified that the assumptions and initial conditions used in the BWROG generic report are representative of LGS.

- II.K.3.45 EVALUATION OF DEPRESSURIZATION WITH OTHER THAN ADS

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.

Response

The applicant endorses the BWROG position on Item II.K.3.45 for LGS. This position is presented in Reference 1.13-11 and is summarized below.

An evaluation of alternate modes of depressurization other than full actuation of the ADS was made by the BWROG 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 to 180 psig in approximately 3.3 minutes. The alternate modes of depressurization that were evaluated considered vessel depressurization over the same pressure range (1050 to 180 psig) within two different time periods (6-10 minutes and 15-20 minutes). The cases considered show that no appreciable improvement can be gained by slower depressurization based on core cooling considerations. Because a full ADS blowdown is well within the design basis of the RPV and ADS is properly designed to minimize the threat to core cooling, no change in the depressurization rate is necessary, and no modifications to LGS are needed for this TMI item.

- II.K.3.46 RESPONDING TO MICHELSON CONCERNS

Position

GE should provide a response to the Michelson concerns as they relate to BWRs.

Clarification

GE provided a response to the Michelson concerns as they relate to BWRs by letter dated February 21, 1980. Licensees and applicants should assess applicability and adequacy of this response to their plants.

Response

All of the generic February 21, 1980 GE responses are applicable to LGS Units 1 and 2 and are adequate in terms of a response to the Michelson concerns for LGS.

- III.A.1.1 EMERGENCY PREPAREDNESS, SHORT-TERM

Position

Comply with 10CFR50, Appendix E and Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and meet the essential elements of NUREG-75/111, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," or have a favorable finding form the Federal Emergency Management Agency.

Response

Emergency planning is discussed in the Emergency Plan.

- III.A.1.2 UPGRADE EMERGENCY SUPPORT FACILITIES

Position

Establish an interim onsite TSC separate from, but close to, the control room for engineering and management support of reactor operations during an accident. The TSC shall be large enough for the necessary utility personnel and five NRC personnel, have direct display or call-up of plant parameters, and dedicated communication with the control room, emergency operations facility, and the NRC. Provide a description of and a completion schedule for establishing a permanent TSC in accordance with the regulatory position of NUREG-0696, "Functional Criteria for Emergency Response" (February 1981).

Establish an onsite OSC, separate from but with communications to the control room for use by operation support personnel during an accident.

Designate a near-site EOF with communications with the plant to provide evaluation of radiological releases and coordination of all onsite and offsite activities during an accident.

These requirements shall be met before fuel loading.

Response

The three types of emergency response facilities required by Section 8 have been provided for LGS.

The TSC meets all of the requirements of section 8.2.1 and is fully functional.

The OSC meets all of the requirements of section 8.3.1 and is fully functional.

The EOF is located approximately 20 miles from the LGS site. The EOF meets all of the technical requirements of section 8.4.1 and is fully functional.

Staffing of the EOF and the TSC is described in the Emergency Plan.

- III.A.2 EMERGENCY PREPAREDNESS

Position

(1) Each nuclear facility shall upgrade its emergency plan to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

(2) 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.

Response

Emergency planning is discussed in the Emergency Plan.

- III.D.1.1 PRIMARY COOLANT OUTSIDE CONTAINMENT

Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

(1) Immediate leak reduction

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

  (b) Measure actual leakage rates with system in operation and report them to the NRC.

(2) Continuing Leak Reduction - Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

Clarification

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

(1) Systems that should be leak tested are as follows (any other plant system which has similar functions or postaccident characteristics even through not specified herein, should be included):

 (a) RHR,

 (b) Containment spray recirculation,

 (c) HPCI recirculation,

 (d) Containment and primary coolant sampling,

 (e) RCIC,

 (f) Makeup and letdown (pressurized water reactors only), and

 (g) 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.

(2) Testing of gaseous systems should include helium leak detection or equivalent testing methods.

(3) Should consider program to reduce leakage potential release paths due to design and operator deficiencies as discussed in our letter to all operating nuclear power plants regarding North Anna and related incidents, dated October 17, 1979.

Response

A review of all systems designed to handle highly radioactive fluids during or after a serious transient or accident has been performed to ensure that appropriate design features to minimize leakage have been included. System isolation provisions have been reviewed in conjunction with this effort (Section 6.2.7). A leak reduction program for these systems will be implemented prior to and after fuel load to measure actual leakage rates and to identify sources of leakage in order that total leakage may be reduced to as-low-as-practical levels. The leakage reduction program is described in Section 6.2.8.

The October 17, 1979, NRC generic letter regarding radioactive releases to North Anna Unit 1 expanded the scope of NUREG-0737 Item III.D.1.1 to include a review of potential radioactive release pathways that would not be related to the handling of highly radioactive fluids during or after a core damage event. This generic letter required "...that release paths exemplified by the

North Anna Unit 1 incident or similar release paths as identified in IE Circular 79-21 should also be considered."

In response to this request per clarification (3), above, a review has been performed to identify all potential unplanned release paths for radioactive fluids during normal plant operation. As shown in Table 1.13-4, it has been determined that existing design provisions and administrative controls are sufficient to prevent unplanned and unmonitored releases of radioactivity.

During review of IE Bulletin 80-10, all interfaces between normally nonradioactive and radioactive systems were identified. It was determined that design provisions adequately maintain boundaries between nonradioactive/radioactive interfaces (Item 4 in Table 1.13-4). These design provisions include one of the following:

a. Two normally closed valves in series

b. One normally closed valve and one check valve in series

c. Two check valves in series

d. Heat exchanger tube sheets (in most cases, the nonradioactive fluid is maintained at a higher pressure than the radioactive fluid).

In the event that leakage or operator errors (e.g., valve mispositionings or incorrect valve lineups) lead to contamination of a nonradioactive system, the process sampling system and numerous grab sampling points for the following normally nonradioactive systems are provided to support a routine contamination monitoring program:

a. Circulating water

b. RECW

c. TECW

d. Clarified water

e. Makeup demineralizers

f. Drywell chilled water

g. Auxiliary steam (both steam and feedwater)

h. Plant waste water effluent

i. Service water

j. Instrument and service air

In addition to the above sampling provisions, the following systems are monitored for radioactive contamination by the process radiation monitoring system:

a. ESW and RHR service water

b. RECW

c. Service water

In the event that a nonradioactive system is found to be contaminated, corrective action will be taken to prevent leakage to the environment and isolate and repair the source of the contamination.

• III.D.3.3 IMPROVED INPLANT IODINE INSTRUMENTATION UNDER ACCIDENT CONDITIONS

Position

(1) 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.

(2) Each applicant for a fuel loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedure necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

Clarification

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver zeolite) for the following reasons:

(1) 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.

(2) Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

(3) Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

(4) 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 SCA. The SCA window should be calibrated to the 365 KeV of I-131 using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

Response

Sampling methods and procedures have been implemented at LGS which will permit the measurement of in-plant iodine concentrations during accident conditions. A description of this method is as follows:

> The sampling method uses portable air samplers with a combination particulate filter and iodine sampling cartridge sampling head. The sampling heads use a glass fiber particulate filter and a CESCO style (2.25" diameter by 1.04" thickness) iodine charcoal cartridge. The cartridge normally used is the CESCO-type charcoal cartridge. When long sampling times are required, a larger capacity charcoal cartridge is available. During emergency conditions, with high xenon or krypton concentrations potentially present, either a silver zeolite or a silver impregnated silica gel adsorber canister will be employed.
>
> Iodine activity on the sample cartridge will be determined by gamma isotopic analysis using a computer based multichannel analyzer with high resolution intrinsic germanium detectors located in the LGS counting room. The counting room is located in the radwaste enclosure at el 217'. An assessment of the NUREG-0737 shielding study indicates that the counting room dose rates and airborne radioactivity concentrations are low enough to permit sample analysis during accident conditions.
>
> Isotopic analysis will permit iodine identification in the presence of xenon and krypton. If the analysis of iodine becomes impossible due to interference (high background) from xenon or krypton, then either silver zeolite cartridges will be used or the charcoal cartridge will be purged with clean bottled nitrogen or breathing air to reduce the interference. If the use of silver zeolite does not sufficiently reduce the xenon or krypton interference, the silver zeolite cartridges will also be purged with clean bottled nitrogen or bottled breathing air available onsite.

The Health Physics technical staff have been trained in the implementation of this postaccident procedure.

- III.D.3.4 CONTROL ROOM HABITABILITY

Position

In accordance with Item III.D.3.4 applicants 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 DBA conditions (GDC 19).

Clarification

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

(2) All applicants with control rooms that meet the criteria of the following sections of the SRP:

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

shall report their findings regarding the specific SRP sections as explained below. References 1.13-12, 1.13-13 and 1.13-14 should be used for guidance.

Applicants 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, applicants may reference their past submittals. Applicants should, however, ensure that these submittals reflect the current facility design and that the information requested in Table 1.13-12 is provided.

(3) All applicants with control rooms that do not meet the criteria of the above listed references, SRPs, regulatory guides, and other references shall perform the necessary evaluations and identify appropriate modifications.

Each applicant 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 DBAs. 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 boundary. Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of the control room habitability but is not all inclusive.

The DBA radiation source term should be for the LOCA containment leakage and ESF leakage contribution outside containment as described in Section 15.6.5, appendices A and B. In addition, BWR facility evaluations should add any leakage from the MSIVs (i.e, valve steam leakage, valve seat leakage, MSIV Leakage Alternate Drain Pathway release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering our recommendations in section D of Regulatory Guide 1.95 (Rev 2) regarding MSIV-LCS. 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 GDC 19, the applicant should submit sufficient information needed for an independent evaluation of the adequacy of the habitability systems. Table 1.13-12 lists the information that should be provided along with applicant's evaluation.

Response

The information required for control room habitability evaluation as listed in Table 1.13-12 is provided in Sections 1.2, 2.2, 6.4, and 9.4. LGS complies with all criteria of control room habitability in accordance with Item III.D.3.4.

1.13.3 REFERENCES

1.13-1 D. H. Slade, ed., Meteorology and Atomic Energy, TID 24190 (1968).

1.13-2 K. G. Murphy and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19", 13th AEC Air Cleaning Conference.

1.13-3 Start, G. E., J. H. Cate, C. R. Dickson, N. R. Ricks, G. H. Ackerman, and J. F. Sagendorf, "Rancho Seco Building Wake Effects on Atmospheric Diffusion", NOAA Technical Memorandum, ERL ARL-69 (1977).

1.13-4 Walker, D. H., R. N. Nassano, M. A. Capo: "Control Room Ventilation Intake Selection for the Floating Nuclear Power Plant", 14th ERDA Air Cleaning Conference (1976).

1.13-5 D. J. Wilson, "Contamination of Air Intakes from Roof Exhaust Vents", ASHRAE Trans. 82, Part 1 pp. 1024-1038 (1976).

1.13-6 R. J. B. Bouwmeester, K. W. Kothari, R. N. Meroney, "An Algorithm to Estimate Field Concentrations Under Nonsteady Meteorological Conditions from Wind Tunnel Experiments", NUREG/CR-1474, NRC, (9/80).

1.13-7.1 General Electric Emergency Response Information System, Licensing Topical Report,

1.13-8 General Electric Licensing Topical Report, NEDE-24988-P and NEDE-24988.

1.13-9 "Proposed Interim Amendments to 10CFR50 Related to Hydrogen Control and Certain Degraded Core Considerations", SECY-80-399, Federal Register, (October 2, 1980).

1.13-10 Letter to D.G. Eisenhut (NRC) from T.J. Dente (BWROG), "Supplement to BWR Owner's Group Evaluation of NUREG-0737, Item II.E.4.2(7)", (June 14, 1982).

1.13-11 "BWR Owners' Group NUREG-0737 Implementation: Analysis and Positions Submitted to the NRC", GE NEDO-24951, (June 1981).

1.13-12 Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release".

1.13-13 Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release".

1.13-14 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).

Table 1.13-1

VITAL AREA RADIATION DOSES[8]

	PIPING AND CLOUD SHINE							
VITAL AREAS(1)	MAJOR SOURCE	PEAK DOSE RATE (Rem/hr)	TOTAL DOSE (Rem)	AIRBORNE WHOLE BODY DOSE (Rem) (2)	SHINE PLUS WHOLE BODY DOSE (Rem)	DOSE OBJECTIVE (Rem)	AIRBORNE ORGAN DOSES (Rem)	DOSE OBJECTIVES (Rem)
Continuous Occupancy								
Main Control Room [8] (SRP 6.4 Occupancy)	ECCS/RHR pipe	1.1	4.2	4.3×10^{-1}	4.6	≤5.0	Thyroid: $6.29 \times 10^{\circ}$[4] Skin : 7.6	≤30 ≤30
Technical Support Center (SRP 6.4 Occupancy)	RHR Pipe/Reactor Enclosure Cloud	2.7×10^{-3}	1.5×10^{-2}	1.47×10^{-1}	1.62×10^{-1}	≤5.0	Thyroid: 2.3×10^{-1} Skin : 3.6×10^{-1}	≤30 ≤30
Operational Support Center (SRP 6.4 Occupancy)	RHR Pipe/Reactor Enclosure Cloud	6.6×10^{-3}	6.7×10^{-2}	1.97	2.0	≤5.0	Thyroid: ≤30[5] Skin : 1.6	≤30 ≤30
Security Center (SRP 6.4 Occupancy)	RHR Pipe/Reactor Enclosure Cloud	1.7×10^{-1}	7.3×10^{-1}	1.3	2.0	≤5.0	Thyroid: ≤30[5] Skin : 1.03	≤30 ≤30
Infrequent Occupancy								
Counting Room(6)	ECCS/RHR Pipe	5.5×10^{-4}	1.3×10^{-3}	1.2×10^{-1}	1.3×10^{-1}	≤5.0	Thyroid: 21.5 Skin : 1.2	≤30 ≤30
Radiochemical Laboratory(6)	ECCS/RHR Pipe	9.3×10^{-3}	3.0×10^{-2}	1.2×10^{-1}	1.6×10^{-1}	≤5.0	Thyroid: 21.6 Skin : 1.2	≤30 ≤30
Postaccident Sampling Station (31 min Occupancy at time = 1 hour) Post-LOCA	H_2 Recombiner/ ECCS Pipe	6.6×10^{-1}[3]	3.4×10^{-1}[3]	2.5×10^{-3}	3.4×10^{-1}[3]	≤5.0	Thyroid: 2.9×10^{-3} Skin : 3.7×10^{-2}	≤30 ≤30
North Stack Instrument Room (1 hour Occupancy)	North Stack	3.9	3.9	8.7×10^{-1}	4.8 [7]	≤5.0	Thyroid: 1.8×10^{-2} Skin : 4.2×10^{-1}	≤30 ≤30
HVAC Panels (1 hour Occupancy)	ECCS/RHR Pipe	3.8×10^{-1}	3.8×10^{-1}	8.8×10^{-2}	4.7×10^{-1}	≤5.0	Thyroid: 3.2×10^{-2} Skin : 4.1×10^{-1}	≤30 ≤30
Radwaste Control Room (6)	ECCS/RHR Pipe	2.1×10^{-2}	6.7×10^{-2}	2.36×10^{-1}	3.0×10^{-1}	≤5.0	Thyroid: ≤30[5] Skin : 1.2	≤30 ≤30
Diesel Generator Area (1 hour Occupancy)	ECCS/RHR Pipe/Reactor Enclosure Cloud	8.1×10^{-3}	8.1×10^{-3}	3.0×10^{-2}	4.4×10^{-2}	≤5.0	Thyroid: 5.0×10^{-2} Skin : 2.0×10^{-2}	≤30 ≤30

(1) Occupancy factors used to calculate doses are listed in parentheses for each vital area. SRP 6.4 occupancy factors are for 30 days. For vital areas with 1 hour occupancy, the doses reflect 1 hour occupancy at the maximum postaccident dose rate unless otherwise specified.

(2) Airborne whole body doses are specified for the listed vital areas.

(3) Doses do not include shine from sample source. See Table 11.5-3 .

(4) MCR Dose was calculated assuming zero inleakage through the MCR Doors. This requires installation of a MCR door seal described in section 6.4 and 15.10.

(5) The calculated Airborne Organ dose was approximately 35 rem over 30 days. Emergency Response Procedures specify the criteria for radiological habitability monitoring to insure the dose objectives are not exceeded. Ba the results of the habitability monitoring personnel in the affected areas maybe instructed to don protective devices or limit stay times to maintain the dose objectives.

(6) The stay times assumed for these areas are half of the stay times specified in SRP 6.4.

(7) Doses to personnel traversing the Refuel Floor on route to and then occupying the North Stack Instrument Room would be 2.86 Rem if a LOCA were to occur while the upper layer of the reactor well shield plugs were removed in OPCON 1, 2 and 3. Doses to personnel traversing the turbine enclosure roof to the reactor enclosure roof on route to and from, and while occupying the North Stack Instrument Room would be 2.9 Rem, if a Unit 2 LOCA were to occur, and 3.957 Rem, if a Unit 1 LOCA were to occur, when both layer of the shield plugs are removed in OPCON 3. These lower doses are a result of a more location specific analysis of the travel routes. The 4.8 Rem value remains the bounding value in all other conditions and areas until specific analysis are performed.

(8) The information in this Table is historical and represents original plant design requirements. The application of Alternative Source Terms per Regulatory Guide 1.183, resulted in the recalculation of control room dose. See Chapter 15 for details.

Table 1.13-2

RADIATION DOSES FOR VITAL AREA ACCESS PATHS(1) (2) (5) (7)

Access Path (2)	Transit Time (min.)	Peak Piping and Cloud Shine Dose (Rem)	Peak Airborne Whole Body Dose (Rem)	Sum of Shine Plus Whole Body Dose (Rem)	Peak Airborne Thyroid Dose (Rem)	Peak Airborne Skin Beta Dose (Rem)
A	4	$6x10^{-3}$	$1x10^{-3}$	$7x10^{-3}$	$1.4x10^{-2}$	$9x10^{-4}$
A' (Alternate)	3	$2x10^{-3}$	$1x10^{-3}$	$3x10^{-3}$	$1x10^{-2}$	$7x10^{-4}$
B	2	$3x10^{-3}$	$5x10^{-4}$	$4x10^{-3}$	$7x10^{-3}$	$5x10^{-4}$
C	0.5	$3x10^{-3}$	$8x10^{-4}$	$4x10^{-3}$	$1x10^{-2}$	$7x10^{-4}$
C' (Alternate)	3	$3x10^{-2}$	$5x10^{-3}$	$4x10^{-2}$	$7x10^{-2}$	$5x10^{-3}$
D	2	$2x10^{-1}$(3)	$5x10^{-4}$	$2x10^{-1}$(3)	$7x10^{-3}$	$5x10^{-4}$
D' (Alternate)	4	$5x10^{-3}$(3)	$1x10^{-3}$	$6x10^{-3}$(3)	$1.4x10^{-2}$	$1x10^{-3}$
E	(4)	(4)	(4)	(4)	(4)	(4)
E' (Alternate)	15	$3x10^{-3}$	$2.4x10^{-2}$	$3x10^{-2}$	$3.3x10^{-1}$	$2x10^{-2}$
E''(Alternate)						
Unit 1 LOCA	15	$7.8x10^{-1}$(6)	$2.4x10^{-2}$	$8.0x10^{-1}$	$3.3x10^{-1}$	$2x10^{-2}$
Unit 2 LOCA	15	$2.5x10^{-1}$	$2.4x10^{-2}$	$2.7x10^{-1}$	$3.3x10^{-1}$	$2x10^{-2}$
F	2	$1x10^{-3}$	$4x10^{-3}$	$5x10^{-3}$	$5.1x10^{-2}$	$4x10^{-3}$
F' (Alternate)	0.5	$6x10^{-3}$	$1x10^{-3}$	$7x10^{-3}$	$1.3x10^{-2}$	$9x10^{-4}$

(1) Dose rates for all parts of access paths are $\leq$10 Rem/hour except as noted in Table 1.13-3.
(2) Access paths are described in Table 1.13-5.
(3) Dose rates will increase slightly at time t = 36 hours when the H_2 recombiner starts operating, but doses will still be below the peak values shown in this table.
(4) Path is not accessible. See Table 1.13-3.
(5) The above doses exclude the impact of the MSIV leakage alternate drain pathway. This source is significant only for paths through the Turbine Enclosure. SCBAs may be required for thyroid protection.
(6) This is an increase of 1.057 Rem (total) above the unit 2 LOCA dose due to the shine from the unit 1 drywell head through the reactor building north wall. These doses are based on the lower layer of reactor well shield plugs being removed on one unit in OPCON 3, and both layers of the other unit being installed or have the unit in OPCON 4 or 5.
(7) The information in this Table is historical and represents original plant design requirements based on source terms consistent with TID-14844. The application of Alternative Source Terms per Regulatory Guide 1.183 may be used to determine vital area radiation doses for subsequent evaluations.

Table 1.13-3

SOLUTIONS TO POTENTIAL VITAL AREA ACCESS PROBLEMS[1][2]

Potential Problem Area	Description	Solution	Remarks
Access Path D	The northeast area of the radwaste enclosure at el 217' near the airlock for the reactor enclosure will have radiation levels of 20 R/hr at time t = 0 hours.	It is preferable to use access path D' instead of access path D until the dose rate falls below 10 Rem/hr in the vicinity of the airlock.	From Figure 1.13-1, it can be seen that the dose rate near the airlock will fall below 10 Rem/hr about 2 hours after a DBA. Access path D would be used for access to the radwaste control room, radiochemical laboratory, or counting area from the control room.If access is required before the dose rate for access path D has fallen to acceptable levels, the operators can use access path D' to enter the radwaste control room. However, it is not necessary to prohibit access in the vicinity of the airlock because the radiation levels decay rapidly and are in a localized area with short transit.
Access Path E	The stairway next to the reactor enclosure exhaust stack will have peak radiation levels of 28 R/hr at time t = 4 hours.	Access path E' should be used until the dose rate falls below 10 R/hr in the stairway. If both the upper and lower reactor well shield plugs are removed, then use path E''	The first sample from the north stack instrument room must be taken within 24 hours. Due to the long time required to pass through the stairway in access path E and the extent of the radiation field, access to the north stack instrument room using this stairway is not possible until after time t = 24 hours.
Access Path E'	If both reactor well shield plugs on either Unit are removed, the refueling floor travel path will have radiation levels of 100 R/hr at t = 0 hours.	Access path E'' should be used until the dose rate falls below 10 R/hr on the refueling floor.	Access to the refueling floor will not drop below 10 R/hr until after time t = 9 hrs.

(1) Access paths are described in Table 1.13-5.
(2) This information had not been updated to reflect the current licensing design basis. The information should be used for historical reference only and not to support the design basis of the plant.

Table 1.13-4

POTENTIAL UNPLANNED RELEASE PATHS

System(s)	Boundary	Potential Release Path	Administrative Control
Air Removal and Sealing Steam	HV-07-142, -143, -144, -145, (Normally Closed)	Airborne contamination release (local) if valves left open after equalizing pressures	Operating procedure requires valve closure
Liquid Radwaste Equipment Drain Processing	62-0021 (Normally Closed)	Airborne contamination release (local) if valve is left open	Operating procedure requires valve closure
Control Rod Drive	XV-47-1F180 XV-47-1F181 XV-47-1F010 XV-47-1F011 (All valves fail closed)	Scram discharge header volume release to DRW or equipment drain collection tank	Operating procedure provides precaution notice
Various Nonradioactive Systems	Valves or heat exchanger tube sheets	Potential cross contamination at radioactive/nonradioactive system interfaces	Routine analysis in chemistry surveillance
Plumbing and Drainage	Open area drains and/or equipment drains	Inappropriate use of segregated drain systems	Precaution notices, drain plugs, curbs and/or color-coded labels around drains to identify
Plumbing and Drainage	Open area and/or equipment drains inside reactor	Open drains are a potential path for air flow from enclosure (air supply fan area and refueling floor)	Controlled opening of plugged drains secondary containment, if the ¼ in. wg. negative pressure is interrupted
Liquid Radwaste Collection	Offsite disposal of sump oil	Sump oil is potentially contaminated	Chemistry sample analysis required prior to disposal
Liquid Radwaste and Waste Water	Release of final radwaste batch to cooling tower blowdown (monitored)	Unauthorized release (inadvertent)	Routine surveillance

Table 1.13-5

ACCESS PATH IDENTIFICATION[1]

Access Path	Route Description	Reference (Bechtel) Drawings
A (TSC to Security Center and Main Control Room/Operation Support Center)	From TSC (yard), proceed to the security center (administration building). Continue west to the Unit 2 turbine enclosure entrance (el 217', Columns 41 & K). Entering turbine enclosure (corridor 354), proceed west to the control structure. Continue to stairs/elevator (Columns 20 & N), then proceed upstairs to el 269'. Enter main control room or exit north for OSC.	8031-C-2, M-102, M-103, and M-104
A' (Alternate to A)	From TSC (yard), proceed to the turbine enclosure truck bay (room 335, el 217 ft', Columns 22 & R) Enter bay and take stairs (Columns 22 & R) to el 269'. Exit stairs to the south for either the OSC or main control room.	8031-C-2, M-102, M-103, and M-104
B (Security Center to Turbine Enclosure/ Control Structure, el 217')	From security center, proceed west to turbine enclosure Unit 2 entrance at el 217', Columns 41 & J. Continue west across Unit 2 turbine enclosure (corridor 354) to the control structure or Unit 1 turbine enclosure.	8031-C-2 and M-102
C (Main Control Room to HVAC Panel Area)	In main control room, proceed to stairs/elevator (Columns N & 20). Continue up stairs/elevator to el 304'. Exit into HVAC panel area.	8031-M-104 and M-105
C' (Alternate to C)	Exit main control room through control structure into turbine enclosure at el 269'. Proceed to stairs near Columns J & 5 and continue upstairs to el 302'. Enter exhaust fan area and proceed east to control structure and enter HVAC panel area.	8031-M-104 and M-105
D (Main Control Room to PASS and the Radwaste Enclosure Vital Areas)	In main control room, proceed to stairs/elevator near Columns N & 20. Continue downstairs to el 217'. Exit stairwell. This area contains the PASS. To continue to the vital areas located in the radwaste enclosure, exit the control structure to the Unit 1 turbine enclosure. Proceed west to the radwaste enclosure entrance at Columns J & 14. Enter radwaste area and continue south for control room or west for chemistry lab and counting room.	8031-M-104, M-103 and M-102

Table 1.13-5 (Cont'd)[1]

Access Path	Route Description	Reference (Bechtel) Drawings
D' (Alternate to D)	In main control room, proceed to stairs/elevator near Columns N & 20. Continue downstairs to el 217' and the PASS. Exit control structure and proceed west (corridor 352) to turbine enclosure exit (Columns Jb & 5). Exit building and proceed south to the end of the radwaste enclosure, then turn east. Enter radwaste enclosure near Columns 13 & C. Proceed north to vital areas.	8031-M-104, M-103 and M-102
E (Radwaste Enclosure el 217' to North Stack Instrument Room)	Exit the radwaste enclosure at Columns J & 14. Walk east through Unit 1 turbine enclosure to control structure. Walk up stairs at Columns M & 20 to el 332'. Proceed southeast across room to stairs at Columns J & 21.8 next to the north stack. Climb stairs to el 411', north stack instrument room.	8031-M-102, M-103, M-104, M-105 M-124, and M-139
E' (Alternate to E)	Exit the radwaste area at Columns J & 14. Continue east through turbine enclosure into Unit 2 side After entering Unit 2 side, continue east to the Unit 2 reactor enclosure entrance (Column 32). Enter stairs near Columns J & 32 and continue up the stairs to el 352' (refueling floor). Proceed south on refueling floor to the door on the south wall between the two units (Columns 22 & D). Enter door and proceed up ladder to south stack instrument area (el 411'). Cross roof area to north stack instrument room.	8031-M-102, M-103, M-104, M-105, M-106, and M-139
E'' (Alternate to E & E', if both reactor well shield plugs are removed)	Personnel shall use the most dose-efficient pathway to enter the 217' elevation of the control structure. Continue up stairs at Columns M and 20 to elevation 324'. Proceed out onto turbine enclosure roof Take scaffold stairs at Columns Kg and 17.6 to reactor enclosure roof elevation 411', proceed along farthest north point of travel on roof to north stack instrument room WRAM sample area.	8031-M-102, M-103, M-104, M-105, M-106, and M-139
F (Radwaste Enclosure el 217' to Diesel Generator Bays	Proceed south through radwaste enclosure to exit at Columns C & 13. Enter yard and move towards south) entrance of the emergency diesel generator bays. Enter bay area.	8031-M-102
F' (Alternate to F)	Proceed south through radwaste enclosure and exit into yard. Continue northeast towards reactor enclosure. Enter generator bays through the north entrance.	8031-M-102

[1] This information has not been updated to reflect the current licensing design basis. The information should be used for historical reference only and not support the design basis of the plant.

Table 1.13-6

RADIATION QUALIFICATION OF SAFETY-RELATED EQUIPMENT(1)

Containment	LOCA Source Term (Noble Gas/Iodine/ Particulate)	Non-LOCA HELB Source Term (Noble Gas/Iodine/Particulate)
Outside	Percent (100/50/1) in RCS	Percent (10/10/0) in RCS
Inside	Larger of (100/50/1) <u>or</u> (100/50/1) in RCS	(10/10/0) In RCS in containment

(1) This Table is based on the requirements of Regulatory Guides 1.3, 1.5, and 1.25, consistent with the source terms of TID-14844. Alternative Source Terms, per Regulatory Guide 1.183 requirements may be used for the qualification of safety related equipment.

Table 1.13-7

X/Q VALUES FOR VITAL AREAS[2]

	Time Periods (hours)	Base X/Q (sec/m^3)	Modifying Factors f_1	f_2	f_3	f_4	f_5	f_6	Final X/Q (sec/m^3)
Technical Support Center	0-8	1.58x10^{-4}	1	1	.2	1	.5	.66[1]	1.04x10^{-5}
	8-24	1.58x10^{-4}	.67	.88	.2	1	.5	.66[1]	6.15x10^{-6}
	24-96	1.58x10^{-4}	.50	.75	.2	1	.5	.66[1]	3.91x10^{-6}
	96-720	1.58x10^{-4}	.33	.50	.2	1	.5	.66[1]	1.72x10^{-6}
	720 & on	1.58x10^{-4}	.25	.33	.2	1	.5	.66[1]	8.6 x10^{-7}
Diesel Generator Areas	0-8	2.57x10^{-4}	1	1	.2	1	.5	.66[1]	1.70x10^{-5}
	8-24	2.57x10^{-4}	.67	.88	.2	1	.5	.66[1]	1.00x10^{-5}
	24-96	2.57x10^{-4}	.50	.75	.2	1	.5	.66[1]	6.36x10^{-6}
	96-720	2.57x10^{-4}	.33	.50	.2	1	.5	.66[1]	2.80x10^{-6}
	720 & on	2.57x10^{-4}	.25	.33	.2	1	.5	.66[1]	1.40x10^{-6}
Security Center	0-8	5.16x10^{-4}	1	1	.2	1	.5	.66[1]	3.41x10^{-5}
	8-24	5.16x10^{-4}	.67	.88	.2	1	.5	.66[1]	2.01x10^{-5}
	24-96	5.16x10^{-4}	.50	.75	.2	1	.5	.66[1]	1.28x10^{-5}
	96-720	5.16x10^{-4}	.33	.50	.2	1	.5	.66[1]	5.62x10^{-6}
	720 & on	5.16x10^{-4}	.25	.33	.2	1	.5	.66[1]	2.81x10^{-6}
Turbine Building HVAC Air Intakes - PASS, OSC	0-8	8.25x10^{-4}	1	1	.2	1	.5	.66[1]	5.45x10^{-5}
	8-24	8.25x10^{-4}	.67	.88	.2	1	.5	.66[1]	3.21x10^{-5}
	24-96	8.25x10^{-4}	.50	.75	.2	1	.5	.66[1]	2.04x10^{-5}
	96-720	8.25x10^{-4}	.33	.50	.2	1	.5	.66[1]	8.98x10^{-6}
	720 & on	8.25x10^{-4}	.25	.33	.2	1	.5	.66[1]	4.49x10^{-6}
Radwaste Building HVAC Air Intake - Radiation Chemistry Lab, Counting Room, Radwaste Control Room	0-8	6.19x10^{-4}	1	1	.2	1	.5	.66[1]	4.09x10^{-5}
	8-24	6.19x10^{-4}	.67	.88	.2	1	.5	.66[1]	2.41x10^{-5}
	24-96	6.19x10^{-4}	.50	.75	.2	1	.5	.66[1]	1.53x10^{-5}
	96-720	6.19x10^{-4}	.33	.50	.2	1	.5	.66[1]	6.74x10^{-6}
	720 & on	6.19x10^{-4}	.25	.33	.2	1	.5	.66[1]	3.37x10^{-6}
Main Control Room, HVAC Panels, and North Stack Instrument Room	0-8								3.46x10^{-4}
	8-24								2.04x10^{-4}
	24-96								1.30x10^{-4}
	96-720								5.71x10^{-5}
	720 & on								2.85x10^{-5}

(1) For the MSIV Leakage Alternate Drain Pathway, the F_6 factor is 1.0, since this release point is not an elevated release point.

(2) This Table is historical. The application of Alternative Source Terms per Regulatory Guide 1.183 resulted in the re-evaluation of X/Q values. See UFSAR Section 2.3.

Table 1.13-8

HIGH-RANGE NOBLE GAS EFFLUENT MONITORS (TABLE II.F.1-1)

REQUIREMENT	-	Capability to detect and measure concentrations of noble 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 (μCi/cc) of air at standard temperature and pressure 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 gas changes) should be taken into account.

10^5 μCi/cc	-	Undiluted containment exhaust gases (e.g., PWR reactor building purge, BWR drywell purge through the SGTS).
	-	Undiluted PWR condenser air removal system exhaust.
10^4 μCi/cc	-	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.
10^2 μCi/cc	-	Other release points (e.g., radwaste buildings, fuel handling/storage buildings).

Table 1.13-8 (Cont'd)

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 alternating current.
CALIBRATION	-	Calibrate monitors using gamma detectors to Xe-133 equivalent (1R/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 to 10^5 μCi/cc noble gases. For less than 10^2 μCi/cc, offline monitoring is recommended.
	-	Upstream filtration (prefiltering to remove radioactive iodines and particulates) is not required; however, design should consider all alternatives with respect to capability to monitor effluents following an accident.
	-	For external mounted monitors (e.g., PWR main steam line, the thickness of the pipe should be taken into account in accounting for low-energy gamma radiation.

Table 1.13-9

INTERIM PROCEDURES FOR QUANTIFYING
HIGH-LEVEL ACCIDENTAL RADIOACTIVITY RELEASES (TABLE II.F.1-2)

Applicants are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off-scale.

Examples of major elements of a highly radioactive effluent release special procedures (noble gas).

- Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.

- Provide shielding to minimize background interference.

- Use of an installed monitor (preferable) or dedicated portable monitoring (acceptable) to measure the radiation.

- Predetermined calculational method to convert the radiation level to radioactive effluent release rate.

Table 1.13-10

SAMPLING AND ANALYSIS OR MEASUREMENT OF
HIGH-RANGE RADIOIODINE AND PARTICULATE EFFLUENTS
IN GASEOUS EFFLUENT STREAMS (TABLE II.F.1-3)

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.

- Particulates > 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.

Table 1.13-10 (Cont'd)

ANALYSIS

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

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

Table 1.13-11

CONTAINMENT HIGH-RANGE RADIATION MONITOR (TABLE II.F.1-4)

REQUIREMENT	-	The capability to detect and measure the radiation level within the reactor containment during and the 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 I 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 at least one point per decade of range between 1 R/hr and 10^3 R/hr.

Table 1.13-12

INFORMATION REQUIRED FOR CONTROL ROOM HABITABILITY EVALUATION
(TABLE III.D.3.4-1)

(1) Control room mode operation, i.e., pressurization and filter recirculation for radiological accident isolation or chlorine release

(2) Control room characteristics:

(a) air volume control room

(b) control room emergency zone (control room, critical files, kitchen, washroom, computer room, etc.)

(c) control room ventilation system schematic with normal and emergency air flow rates

(d) infiltration leakage rate

(e) high efficiency particulate air filter and charcoal absorber efficiencies

(f) closest distance between containment and air intake

(g) layout of control room, air intakes, containment building, and chlorine, or other chemical storage facility with dimensions

(h) control room shielding including radiation streaming from penetrations, doors, ducts, stairways, etc.

(i) automatic isolation capability-damper closing time, damper leakage and area

(j) chlorine detectors or toxic gas (local or remote)

(k) self-contained breathing apparatus availability (number)

(l) bottled air supply (hours supply)

(m) emergency food and potable water supply (how many days and how many people)

(n) control room personnel capacity (normal and emergency)

(o) potassium iodide drug supply

Table 1.13-12 (Cont'd)

(3) Onsite storage of chlorine and other hazardous chemicals:

(a) total amount and size of container

(b) closest distance from control room air intake

(4) Offsite manufacturing, storage, or transportation facilities of hazardous chemicals

(a) identify facilities within a 5 mile radius

(b) distance from control room

(c) quantity of hazardous chemicals in one container

(d) frequency of hazardous chemical transportation traffic (truck, rail, and barge)

(5) Technical specifications (refer to Standard Technical Specifications)

(a) chlorine detection system

(b) control room emergency filtration system including the capability to maintain the control room pressurization at $^1/_8$ inch water gauge, verification of isolation by test signals and damper closure times, and filter testing requirements.