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Dalwyn R. Davidson
VICE PRESIDENT
SYSTEM ENGINEERING AND CONSTRUCTION

April 20, 1982



Mr. A. Schwencer
Chief, Licensing Branch No. 2
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Perry Nuclear Power Plant
Docket Nos. 50-440; 50-441
Summary of Responses to
Requirements of NUREG-0737

Dear Mr. Schwencer:

This letter and its enclosure are submitted to provide a current summary of the applicant's responses to the requirements of NUREG-0737, as applicable to the Perry Nuclear Power Plant, Units 1 and 2.

Appendix 1A of the Perry FSAR contains the original TMI Action Plan. This summary encompasses current status and clarifications which have been provided to NRC Staff reviewers during the current review process.

It is our intention to incorporate these responses in a subsequent amendment to our Final Safety Analysis Report.

Very truly yours,

Dalwyn R. Davidson

Dalwyn R. Davidson
Vice President
System Engineering and
Construction

DRD/ml

Enclosure

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cc: John Hilbish, Gilbert Associates, Inc.
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RESPONSE TO REQUIREMENTS OF NUREG-0737

This document contains a response for each TMI-related requirement identified in NUREG-0737 and applicable to Perry Nuclear Power Plant.

## Item No. I.A.1.1

### Shift Technical Advisor

REQUIREMENT

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

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

RESPONSE

PNPP has committed to provide a Shift Technical Advisor who offers shift technical support to the shift supervisor and who advises the shift supervisor on the safety status of the plant, diagnoses plant accidents, and recommends actions to mitigate the consequences of accidents. An STA at PNPP must have a bachelor degree in Engineering or related sciences or a High School diploma and sixty semester hours of college-level education in mathematics, reactor physics, chemistry, materials, reactor thermodynamics, fluid mechanics, heat transfer, electrical and reactor control theory. In addition, an STA must have one year of professional level nuclear power plant experience. The STA's will complete additional instruction at PNPP including pertinent portions of on-site training dealing with FSAR accident analyses, technical specifications, normal and off-normal operating procedures and Perry system operating modes and construction.

## Item No. I.A.1.2

### Shift Supervisor Administrative Duties

REQUIREMENT

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.

RESPONSE

Administrative procedures will be clearly written to define the shift supervisor's command and control responsibilities and authorities and to emphasize his responsibility for safe operation of the plant. Those functions which clearly detract from the shift supervisor's responsibility for assuring safe operation of the plant will be assigned to other personnel.

## Item No. I.A.1.3

### Shift Manning

REQUIREMENT

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

RESPONSE

In the Manning Table shown below, the column headed "Units 1 & 2" lists the intended manning levels with both units in operation. Note that this manning exceeds that specified in NUREG-0737 for a two-unit plant with one control room. Whereas 0737 would require a total of one unit supervisor and three supervising operators, CEI intends to provide two unit supervisors and three supervising operators.

The shift staffing described in the FSAR Section 13.1.2.3 for the Perry Plant control room, with two units operating, provides for six licensed personnel for the two units; three SROs and three ROs. This staffing exceeds the NUREG-0737 interim guidance staffing level for Two Units, One Control Room configuration by one SRO license and is less than the interim guidance staffing level for Two Units, Two Control Rooms by one RO license.

The original Perry Plant control room design was arranged for optimizing the human factors impact for operators moving from one unit to the other in the single control room. This was the basis for arranging the two control boards side by side with identical positioning of all operating devices located on each control board. As a result of fire protection considerations, a partition was installed between the two control boards with a normally closed door in the partition. To accommodate the impact of this partition and for more effective command control during emergency operation, an SRO has been added to each shift crew.

For starting up or shutting down a generating unit, two RO licensed operators are normally required. With three ROs available each shift, one RO will be regularly assigned to each unit with the third RO available for assignment to the unit which may be starting up or shutting down. It is not normally expected that both units would be in that mode of operation at the same time. If such would be the case, an additional RO will be provided by calling out or holding over an extra person if not available on shift. Thus, it does not represent the proper utilization of critically skilled manpower to require full time on shift the fourth RO

licensed operator for those rare instances when he or she would be needed. Therefore, exception is taken to the interim staffing guidance for Two Units, Two Control Rooms as tabulated in NUREG-0737, Page I.A.1.3-4.

PERRY PLANT DEPARTMENT
SHIFT STAFFING
MODES 1, 2, 3

| | Unit 1 | Units 1 & 2 |
|---|---|---|
| Shift Supervisor (SRO) | 1 | 1 |
| Unit Supervisor (SRO) | 1 | 2 |
| Supervising Operator (RO) | 2 | 3 |
| Perry Plant Operator (AO) | 1 | 2 |
| Perry Plant Attendant (AO) | 1 | 2 |
| Radwaste Technician | 1 | 1 |
| Health Physics Technician | 1 | 1 |
| Chemistry Technician | 1 | 1 |
| I&C Technician | 1 | 1 |
| Shift Technical Advisor | 1 | 1 |
| Total | 11 | 15 |

SRO - Licensed Senior Reactor Operator
RO - Licensed Reactor Operator
AO - Auxiliary Operator

## Item I.A.2.1

### Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications

REQUIREMENT*

A. Training programs shall be modified as necessary to provide
(1) Training in heat transfer, fluid flow, and thermodynamics
(2) Training in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged
(3) Increased emphasis on reactor and plant transients.

B. Instructors shall be enrolled in appropriate requalification program.

C. Certifications shall be signed by the highest level of corporate management for plant operation.

D. Requalification programs shall be modified as above, grading criteria shall be modified to be consistent with licensing and additional control manipulations shall be required.

RESPONSE

PNPP has committed to provide on-site training for licensed operators which includes the topics of reactor fundamentals, radiation protection, heat transfer, fluid flow, thermodynamics, plant transients and plant systems as well as updating license candidates on procedures, plant design changes, technical specifications and regulations with which the operator or senior operator must comply. The operator training program will be developed to insure that plant operators, appropriate staff engineers, and management personnel possess the knowledge and skills necessary to recognize potentially severe accident conditions that have resulted or could result in core damage and to mitigate the consequences of such accidents.

Training instructors who teach systems, integrated responses, transients and simulator courses have successfully completed SRO certification through approved General Electric Control Room Simulator Programs. Subsequent to initial fuel load, these instructors shall be required to possess valid NRC SRO licenses or instructor certifications.

The PNPP Operator Requalification Program will include various topic areas such as heat transfer, fluid flow, thermodynamics and mitigation of accidents involving a degraded core.

Certification of training completed pursuant to Sections 55.10a (6) and 55.33a (4) and (5) at 10CFR Part 55 shall be signed by the Vice President, Nuclear.

As Perry is a facility not in operation, the requirements for on-shift training and SRO experience as an RO for one year are not applicable. However, steps are taken to achieve an equivalency. The majority of all license applicants will have previous experience as an NRC licensed operator at another site or as an RO/EWS/EOOW in the Naval Nuclear Power Program. Additionally, candidates assigned to the Operations Section will perform shift duties during the testing phase at Perry prior to initial fuel load. Whenever possible, candidates will also be sent to other operating plants to gain additional experience. Finally, each operating shift will have assigned to it a person with commercial BWR startup experience during the period from fuel load until 100% power is attained or for one year, whichever comes first.

*The above "REQUIREMENT" is taken from H. R. Denton's letter of March 28, 1980. Since the requirements in this letter extend over seven pages, they are presented here in a summary form and as applicable to precritical applicants.

## Item NO. I.A.2.3

### Administration of Training Programs

REQUIREMENT

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

RESPONSE

Personnel selected to act as instructors are individuals with previous technical training experience, civilian or military, and/or above average performance who have demonstrated the potential to effectively communicate in an instructional situation. Instructors responsible for instruction in systems, integrated responses, transients, and simulator courses complete the same training and requalification programs as NRC SRO license candidates. Prior to instructing, these instructors shall have successfully certified at the SRO level through approved General Electric Control Room Simulator Programs. Subsequent to initial fuel load, these instructors shall be required to possess valid NRC SRO licenses or instructor certifications. Additionally, instructors are enrolled in a continuing program which teaches instructional skills. CEI-developed programs to develop instructional abilities are supplemented by university or vendor programs. Finally, all instructors are frequently monitored and evaluated by supervisory staff to ensure continued competency.

## Item No. I.A.3.1

Revise Scope and Criteria for Licensing Examinations--Simulator Exams (Item 3)

REQUIREMENT

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

RESPONSE

All Reactor Operator and Senior Reactor Operator license applicants will prepare to take the new licensing examinations as required by the NRC prior to fuel load. Persons seeking operator and senior operator licenses receive extensive classroom, simulator, and on-the-job training.

NRC Operator License candidates utilize the General Electric Perry Simulator at Inola, Oklahoma for training. Time will be made available on the Perry Simulator for the simulator examination portion of the NRC license examination sequence.

## Item No. I.B.1.2

### Independent Safety Engineering Group

REQUIREMENT

Each applicant for an operating license shall establish an on-site Independent Safety Engineering Group (ISEG) to perform independent reviews of plant operations.

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

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

RESPONSE

The Perry Nuclear Power Plant will have an on-site Independent Safety Engineering Group (ISEG) which will meet the intent of NUREG-0737, I.B.1.2.

The ISEG will form a part of the Nuclear Engineering Department. The group will be staffed by engineers and other technically oriented personnel, all of whom will have qualifications comparable to the requirements set forth in ANSI/ANS 3.1, Sections 4.1 and 4.2 (December 1981). The staff will consist of five individuals from Mechanical, Electrical, Chemical/Environmental and Quality Assurance disciplines, one of whom will be designated as chairman. The chairman of the ISEG will report directly to the Manager of the Nuclear Engineering Department.

The group will not be dedicated full time to the activities of ISEG, however, other assignments will be minimized to assure that time expenditure required to meet the intent of NUREG 0737 will not be impacted.

The charter of the ISEG will include the following scope:

1. The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, LIS advisories and other functions of design and operating experience information that indicate areas for improving plant safety.

2. The ISEG is to perform periodic, independent review of plant activities including maintenance modifications, operational problems and operational analyses.

   As deemed necessary by the ISEG, detailed recommendations regarding improvements will be presented to management.

3. Periodic surveillance of operations and maintenance audits will be conducted to verify that these activities are performed correctly. These activities do not include detailed audits of plant operations; but rather, represent an overview function.

4. The ISEG will evaluate the effectiveness of the operational Quality Assurance program independent of normal functions of the Quality Assurance Department.

Nuclear Engineering Department procedures will be developed to assure that the requirements of the charter and the intents of NUREG 0737 are met.

## Item No. I.C.1

### Guidance for the Evaluation and Development of Procedures for Transients and Accidents

REQUIREMENT

In letters of September 13 and 27, October 10 and 30, and November 9, 1979, the Office of Nuclear Reactor Regulation required licensees of operating plants, applicants for operating licenses and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, including procedures for operating with natural circulation conditions, and to conduct operator retraining (see also item I.A.2.1). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980 and implementation of procedures and retraining were to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions are being developed. In the course of review of these matters on Babcock and Wilcox (B&W)-designed plants, the staff will follow up on the bulletin and orders matters relating to analysis methods and results, as listed in NUREG-0660, Appendix C (see Table C.1, items 3, 4, 16, 18, 24, 25, 26, 27; Table C.2, items 4, 12, 17, 18, 19, 20; and Table C.3, items 6, 35, 37, 38, 39, 41, 47, 55, 57).

RESPONSE

The PNPP has been an active participant in the BWR Owners Group efforts to develop generic emergency procedure guidelines for boiling water reactors. This effort on the part of the BWR Owners Group is partially in direct response to the recommendations outlined in item I.C.1 of NUREG 0737, Clarification of TMI Action Plan Requirements. As a result, these guidelines will be used as the basis for the emergency procedures to be drafted and utilized at the PNPP.

## Item No. I.C.2

### Shift Relief and Turnover Procedures

REQUIREMENT*

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

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

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

*This "REQUIREMENT" is taken from D. B. Vassallo's letter dated 11/9/79 to all licensees of plants under construction since it was not provided in detail in either NUREG-0660 or NUREG-0737.

RESPONSE

Checklists and/or logs will be provided for the control room operators and shift supervisor. The checklists and/or logs will include items such as critical parameters, control console checks for availability and proper alignment of systems essential to the prevention and mitigation of operational transients and accidents and the identification of degraded systems or components (including time in degraded mode) that are addressed by Technical Specifications. Auxiliary operators will review plant status by log reviews. An administrative procedure will address the conduct of shift turnover.

## Item No. I.C.3

### Shift Supervisor Responsibilities

REQUIREMENT

Issue a corporate management directive that clearly establishes the command duties of the shift supervisor and emphasizes the primary management responsibility for safe operation of the plant. Revise plant procedures to clearly define the duties, responsibilities and authority of the shift supervisor and the control room operators.

RESPONSE

A corporate management directive will be issued establishing the command duties of the shift supervisor that emphasizes the primary management responsibility for safe operation of the plant. Plant administrative procedures will define the duties, responsibilities and authority of the shift supervisor and control room operators.

## Item No. I.C.4

### Control Room Access

REQUIREMENT*

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

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, and

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 of the control room.

RESPONSE

Administrative procedures will be developed to address the control of access to the control room and to define the authorities and responsibilities of plant management in the event of an emergency.

*This "REQUIREMENT" is taken from D. B. Vassallo's letter dated 11/9/79 to all licensees of plants under construction since it is not provided in detail in either NUREG-0660 or NUREG-0737.

## Item No. I.C.5

### Procedures for Feedback of Operating Experience to Plant Staff

REQUIREMENT

Review administrative procedures to ensure 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

PNPP will participate in the INPO SEE-IN program. Procedures will be implemented to ensure that all Significant Operating Experience Reports (SOER's) and Significant Event Reports (SER's) are distributed for review, and recommendations for corrective actions appropriate to PNPP are provided to plant staff personnel and incorporated into the training program.

## Item No. I.C.6

### Guidance on Procedures for Verifying Correct Performance of Operating Activities

REQUIREMENT

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

Implementation of automatic status monitoring if required will reduce the extent of human verification of operations and maintenenace activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases--one before and one after installation of automatic status monitoring equipment, if required, in accordance with item 1.D.3.

RESPONSE

The PNPP has committed to compliance with Reg. Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems." In addition procedures will be developed which require the approval of the Unit Supervisor (SRO) to release any system or equipment important to safety for maintenance or surveillance. The approval of the Unit Supervisor will also be required to return any equipment important to safety back into service. Procedures will also be developed to verify and document the functional acceptability of any equipment returned to service which is important to safety. For the return-to-service of ECCS Systems, independent verification of proper systems alignment will be made unless functional testing can be performed without compromising plant safety and can prove that all equipment, valves, and switches involved in the activity are correctly aligned.

## Item No. I.C.7

### NSSS Vendor Review of Procedures

REQUIREMENT

Operating license applicants are required to obtain reactor vendor review of their low-power, power-ascension and emergency procedures as a further verification of the adequacy of the procedures.

RESPONSE

CEI will provide for a review of low power testing, power ascension and emergency operating procedures by the NSSS vendor, General Electric Corporation, prior to implementation of these procedures.

## Item No. I.C.8

### Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants

REQUIREMENT

Correct emergency procedures, as necessary, based on the NRC audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of AC power and steam-line break).

RESPONSE

The Cleveland Electric Illuminating Company is participating in the BWR Owners' Group program to finalize Emergency Procedure Guidelines for General Electric Boiling Water Reactors. Once these guidelines are converted into emergency procedures for PNPP and audited by the NRC, CEI will revise them, as necessary, before full power operation.

## Item No. I.D.1

### Control Room Design Review

REQUIREMENT

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

RESPONSE

CEI in conjunction with the BWR Owners' Group has conducted an assessment of the Perry Control Room to identify signficant human factors deficiencies. The results of this survey are presently being evaluated to determine the priority and corrective actions required. This information should be available for NRC review in May of 1982.

We are presently awaiting NRC agreement on the BWR Owners' Group Control Room Survey program. This information had been submitted to V. A. Moore by W. J. Armstrong on 8/25/81. A follow-up meeting was held with the NRC on 3/10/82. No response has been received from the NRC as to the acceptability of the contents and methods of the Owners Group survey. We are awaiting an answer prior to sending the results of our survey.

## Item No. I.D.2

### Plant Safety Parameter Display Console

REQUIREMENT

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

RESPONSE

The Cleveland Electric Illuminating Company will provide a safety parameter display for operating personnel.

CEI jointly sponsored a program, through the BWR Owners' Group, to develop appropriate parameter lists and displays for the CRT. In addition, two other alternative SPDS display sets have been defined for possible implementation at PNPP.

Simulation evaluations being conducted for PNPP by General Electric will be completed by July, 1982. CEI will then review the results and specify the final SPDS design for PNPP, including the Control Room location of two SPDS video display terminals.

## Item No. I.G.1

### Training During Low Power Testing

REQUIREMENT

Define and commit to a special low power testing program, approved by NRC, to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal start-up test program and to provide supplemental training.

Further clarification of this item includes the need to perform a simulated loss of off-site and on-site A/C power.

RESPONSE

The Cleveland Electric Illuminating Company is a member of the Licensing Review Group II (LRG-II) whose position is to develop a special low power test program using the guidelines provided in the report "BWR Owners' Group Program for Compliance with NUREG-0737, Item I.G.1, Training During Low Power Testing," which was transmitted to the NRC via a letter from D. B. Waters (Chairman-BWR Owners Group) to D. E. Eisenhut (Director of Licensing-NRC) dated February 9, 1981. Licensed personnel and license candidates will participate in this training prior to full power operation.

The LRG-II position is for each plant to review the result from preceding simulated loss of A/C power tests, performed at other BWRs, in order to determine the scope of such testing on their plant. The results of these prior tests will be reviewed, plant specific analyses performed, and recommendations forwarded to the NRC as to whether or not the test, or some portion of it, should be repeated at their plant. LRG-II plants will perform the prescribed scope of tests if such testing is required by the NRC.

## Item No. II.B.1

### Reactor Coolant System Vents

REQUIREMENT

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

RESPONSE

The reactor coolant vent line is located at the very top of the reactor vessel as shown in the schematic (FSAR Figure 5.1-3). This 2-inch line contains two safety-related Class 1E motor-operated valves (B21-F001 and B21-F002) that are operated from the control room. The location of this line permits it to vent the entire reactor pressure vessel, with the exception of the reactor coolant isolation cooling (RCIC) head spray piping which comprises approximately 0.15 $ft^3$ of volume above the elevation of the RPV. This small volume was considered in the original design of the RCIC system and is of no consequence to its operation. In addition, since this vent line is part of the original design for the PNPP units, it has already been considered in all design-basis accident analysis contained elsewhere in the FSAR.

Each Perry Plant unit is provided with nineteen power-operated safety-grade relief valves which can be manually operated from the control room to vent the reactor pressure vessel. The point of connection to the vent lines (main streamlines) from near the top of the vessel to these valves is such that accumulation of gases above that point in the vessel will not affect natural accumulation of gases of the reactor core.

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

The BWR Owners' Group position is that the requirement of single-failure criteria for prevention of inadvertent actuation of these valves, and the requirement that power be removed during normal operation, are not applicable to BWRs. These valves serve an

important function in mitigating the effects of transients and provide ASME code overpressure protection. Therefore, the addition of a second "block" valve to the vent lines would result in a less safe design and a violation of the code. Moreover, the inadvertent opening of a relief valve in a BWR is a design-basis event and is a controllable transient.

In addition to these power-operated relief valves, the Perry Plant BWR/6's include various other means of high-point venting. Among these are:

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

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

c. Main steam-driven reactor core isolation cooling (RCIC) system turbines, operable from the control room, which exhaust to the suppression pool;

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

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

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

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

The small-break accident (SBA) guidelines emphasize the use of HPCS/RCIC as a first line of defense for inventory-threatening events which do not quickly depressurize the reactor. If these

systems succeed in maintaining inventory, it is desirable to leave them in operation until the decision to proceed to cold shutdown is made. Thus the reactor will be vented via RCIC turbine steam being discharged to the suppression pool. Termination of this mode of venting could also terminate inventory makeup if the HPCS had failed also. This would necessitate reactor depressurization via the SRV, which of course is another means of venting.

If the HPCS/RCIC are unable to maintain inventory, the SBA guidelines call for use of ADS or manual SRV actuation to depressurize the reactor so that the low pressure core spray system can inject water. Thus, the reactor would be vented via the SRV to the suppression pool. Termination of this mode of venting is not recommended. It is preferable to remain unpressurized; however, if inventory makeup requires HPCS or RCIC restart, that can be accomplished manually by the operator. It is more desirable to establish and maintain core cooling than to avoid venting. It is emphasized, however,
that emergency venting would not be in the interest of core cooling and, must be employed under Emergency Procedure Guidelines.

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

Conclusion and Comparison with Requirements

The conclusions from this vent evaluation for PNPP are as follows:

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

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

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

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

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

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

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

h. An indication of SRV position is provided in the control room. Temperature sensors in the discharge lines confirm possible valve leakage. This indication is being upgraded in accordance with NUREG-0588.

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

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

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

l. No new 10CFR50.46 conformance calculations are required, because the vent provisions are part of the systems in the plant's original design and are covered by the original design bases.

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

## Item No. II.B.2

### Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May be Used in Post-Accident Operations

REQUIREMENT

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

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

RESPONSE

A review was conducted of the plant identified systems which were likely to contain highly radioactive fluids following a design basis LOCA. The radioactive material was assumed to be instantaneously mixed in those systems, connected either to the reactor coolant system or to the containment atmosphere, that are not isolated at the start of the accident. Non-essential systems that are isolated and have no post-accident function were not considered in the review.

After determining the systems and post-accident source distribution to be used for the shielding review, the SDC point kernel shielding code was used to calculate the associated post-accident radiation doses.

Areas which may require occupancy to permit an operator to aid in the mitigation of an accident are vital areas. The evaluation to determine the necessary vital areas included the control room, technical support center, post-LOCA hydrogen control system, containment isolation system, sampling and sample analysis areas, remote shutdown panel, ECCS alignment functions, motor control

center, instrument panels, emergency power supplies, security center and radwaste control panels. Of these it was determined that for the Perry Plant, the control room and technical support center will require continuous occupancy and the sampling station, sample analysis area and remote shutdown panel will require infrequent occupancy. The remote shutdown panel is available for frequent occupancy if required.

## Item No. II.B.3

### Post-Accident Sampling Capability

REQUIREMENT

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

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

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

The following additional clarifications have also been taken into account in the applicant's response.

Prior to exceeding 5% power operation the applicant must demonstrate the capability to promptly obtain reactor coolant samples in the event of an accident in which there is core damage consistent with the conditions stated below:

1. Demonstrate compliance with all requirements of NUREG-0737, II.B.3, for sampling, chemical and radionuclide analysis capability, under accident conditions.

2. Provide sufficient shielding to meet the requirements of GDC-19, assuming Reg. Guide 1.3 source terms.

3. Commit to meet the sampling and analysis requirements of Reg. Guide 1.97, Rev. 2.

4. Verify that all electrically powered components associated with post accident sampling are capable of being supplied with power and operated, within thirty minutes of an accident in which there is core degradation, assuming loss of offsite power.

5. Verify that valves which are not accessible for repair after an accident are environmentally qualified for the conditions in which they must operate.

6. Provide a procedure for relating radionuclide gaseous and ionic species to estimated core damage.

7. State the design or operational provisions to prevent high pressure carrier gas from entering the reactor coolant system from on-line gas analysis equipment, if it is used.

8. Provide a method for verifying that reactor coolant dissolved oxygen is at $< 0.1$ ppm if reactor coolant chlorides are determined to be $> 0.15$ ppm.

9. Provide information on (a) testing frequency and type of testing to ensure long term operability of the post accident sampling system, and (b) operator training requirements for post-accident sampling.

10. Demonstrate that the reactor coolant system and suppression chamber sample locations are representative of core conditions.

RESPONSE

The planned post-accident sampling system for PNPP will be installed prior to fuel load and will meet NUREG 0737 requirements, including the above listed clarifications.

The vendor that will supply this system and the amount of automatic analysis capabilities has not yet been determined.

This system will be able to sample the following points from a panel to be located on the 577' elevation of the Intermediate Building:

Liquid Samples

- Reactor Water Recirc System (jet pump) (2 points)
- Residual Heat Removal System (2 points)
- Reactor Water Cleanup System (3 points)

Gaseous Samples

- Drywell Atmosphere
- Containment Atmosphere
- Suppression Pool Atmosphere - Annulus Atmosphere

The sample panel will also provide the following grab samples:

- Dilute Reactor Water
- Undiluted Reactor Water
- Dilute Off Gas Sample of Reactor Water
- Non Accident Liquid

In addition, The Cleveland Electric Illuminating Company is a member of the Licensing Review Group (LRG-II) whose generic demonstration of representative sample locations (clarification #10 above) was submitted in LRG-II position papers for issues 1-CHEB and 2-CHEB in a letter from D. L. Holtescher to J. R. Miller dated March 12, 1982. A generic procedure for relating radionuclide gaseous and ionic species to estimated core damage (clarification #6 above) is scheduled for submittal by LRG-II in May 1982.

## Item No. II.B.4

### Training for Mitigating Core Damage

REQUIREMENT

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

RESPONSE

A training program to teach the use of equipment and systems to control or mitigate accidents in which the core is severely damaged is being developed and will be implemented no later than six months prior to fuel loading. This training will address the upgraded emergency procedures developed in response to NUREG-0660/0737 Item I.C.1, "Guidance for the Evaluation and Development of Procedures for Transients and Accidents." The Perry Control Room Simulator will be utilized for operator familiarization with conditions and procedures. The total scheduled presentation time for the entire program shall be 80 hours.

## Item No. II.D.1

Performance Testing of BWR and PWR Relief and Safety Valves

REQUIREMENT

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

RESPONSE

In a letter dated September 7, 1981, from D. R. Davidson to D. Eisenhut, CEI endorsed the BWR Owners Group S/R Valve testing program and verified its applicability to the Dikkers S/R valves used for Perry.

## Item No. II.D.3

### Direct Indication of Relief and Safety Valve Position

REQUIREMENT

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

RESPONSE

The SRV open/close monitoring system selected for PNPP is a single channel safety grade system consisting of a sensing element and a pressure switch, connected to the discharge pipe at the downstream side of the SRV discharge pipe. The electrical output of the pressure switch operates a relay which provide input to the annunciator, process computer, and indicator lights. This system will be environmentally and seismically qualified. This system is identical to that recently proposed for Grand Gulf and approved by NRC.

## Item No. II.E.4.1

### Dedicated Hydrogen Penetrations

REQUIREMENT

Plants using external recombiners or purge systems for post accident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single-failure requirements of General Design Criteria 54 and 56 of Appendix A to 10CFR50, 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.

RESPONSE

The Perry Plant is designed with two 100 percent redundant hydrogen recombiners inside the containment of each unit. This position is therefore not applicable to the Perry Plant. The Post-Accident External Purge System is presently designed to meet the redundancy and single-failure requirements of General Design Criteria 54 and 56 of Appendix A to 10CFR50. Refer to FSAR Section 6.2.5.2.3 for additional information on combustible gas control in containment.

The present system is designed based on hydrogen generation rate calculations using Regulatory Guide 1.7 (Revision 1). The Cleveland Electric Illuminating Company, as a member of the Hydrogen Control Owners Group, has a program underway to improve the capability of the Mark III containment in dealing with significant amounts of hydrogen, well in excess of those considered under 10CFR50.44.

PNPP procedures for the use of combustible gas control systems will be reviewed and revised, as applicable.

## Item II.E.4.2

### Containment Isolation Dependability

REQUIREMENT

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

2. All plant personnel shall give careful consideration to the definition of essential and nonessential systems; identify each system determined to be essential; identify each system determined to be nonessential; describe the basis for selection of each essential system; modify their containment isolation designs accordingly; and report the results of the 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 Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979, must be sealed closed as defined in SRP 6.2.4, Item II.3.f during operational conditions 1, 2, 3 and 4. Furthermore, these valves must be verified to be closed at least every 31 days.

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

RESPONSE

The containment isolation system for PNPP has been reviewed in accordance with NUREG-0737. The results of the review are as follows:

1. In order to evaluate the adequacy of the PNPP containment isolation system, FSAR Table 6.2-32 "Containment Isolation Valve Summary" was reviewed for accuracy, completeness and consistency with the NRC Standard Review Plan Section 6.2.4. The most significant changes appear in the columns labeled "Essential (TMI)" and "Isolation Signal."

2. Because the definition of essential and non-essential systems has been altered since the TMI-2 incident, the containment penetrations were re-evaluated as to their importance in post-accident situations. This re-evaluation was done using the Table 2.1-1 (attached). This table provides an assessment of the PNPP systems which can be considered "Essential" or "Non-Essential" for isolation conditions consistent with NUREG-0578, Requirement 2.1.4. As used in this assessment, those systems identified as essential are regarded as indispensable or are back-up systems in the event of a loss-of-coolant accident. The non-essential systems have been judged to be not required in loss-of-coolant accident situations. However, depending upon the circumstances, it may be highly desirable not to isolate a "non-essential" system. For this reason, the NUREG-0578 definition of "essential" is deliberately flexible. As a result, the specification of "essential" is very judgmental with certain systems. The feedwater penetrations and some instrument air penetrations were upgraded to "essential" under the new TMI-2 definition.

3. All non-essential systems with non-manual containment isolation valves are actuated by at least one automatic isolation signal.

4. Systems, once isolated, should be capable of being quickly returned to service as the need arises. The review of the FSAR Table 6.2-32 also included examining the effect of resetting the containment isolation signal.

   All automatic isolation valves, with the possible exception of the main steam isolation valves, will remain in the "as is" position when the containment isolation signal(s) is reset.

   A further investigation into the control function of the main steam isolation valves will be made to determine if modification(s) is required to keep the valve closed after resetting the containment isolation signal. Also, those valves that are identified with a $RM_c$* in Table 6.2-32, may require a separate remote manual switch in the control room.

5. An evaluation is underway to determine the minimum pressure setpoint.

6. A design review will be done to determine that the containment purge valves meet BTP CSB6-4.

7. PNPP containment purge and vent valves are to close on high radiation signals. Those that do not isolate on high radiation signals are to be "sealed closed" valves.

TABLE 2.1-1

ESSENTIAL/NON-ESSENTIAL EQUIPMENT

(Preliminary Perry Unique Listing Using The Owner Group/GE Systems Work as a Guide

| | | ESSENTIAL | COMMENTS |
|---|---|---|---|
| 1. | Standby Liquid Control | Yes | Should be available as back-up to CRD system. |
| 2. | Core Spray (High & Low Pressure) | Yes | Safety System |
| 3. | Nuclear Closed Cooling Water | No | Used for normal operation only. Not required for DBA, but is used for the recirc., cleanup system operation, and fuel pool heat exchangers. |
| 4. | Combustible Gas Control System | Yes | Combustible gas control function necessary to eliminate hydrogen/ oxygen combustible atmosphere. |
| 5. | Automatic Depres-surization System | Yes | Safety System/Control RPV pressure. |
| 6. | Annulus Exhaust Gas Treatment | Yes | Necessary to control emmissions to environ-ment. |
| 7. | Containment Chiller Water Cooling | Yes | Necessary to cool system pumps and motors. |
| 8. | Reactor Core Isola-tion Cooling | Yes | Necessary for core cooldown following isola-tion from the turbine condenser and feedwater makeup. |
| 9. | Emergency Service Water System | Yes | Necessary to remove heat following accident. Includes the ultimate heat sink. |

TABLE 2.1-1 (Continued)

| | | ESSENTIAL | COMMENTS |
|---|---|---|---|
| 10. | Control Complex Chilled Water | Yes | Cools Control Room. |
| 11. | Instrument Air | Yes | Regarded as essential because this system supports safety equipment. Back-up accumulators are available for the safety equipment should the system fail. |
| 12. | Service Air | No | Serves no safety or shutdown function. |
| 13. | Main Steam* | Yes | Not required for shutdown but can be used as alternate cooling mode. |
| 14. | Feedwater Line* | Yes | Not required for shutdown but can be used as alternate cooling mode. |
| 15. | Reactor Water Sample | No | Not required for shutdown, but would be necessary for post-accident assessment. Post-accident sample is a separate issue. |
| 16. | Control Rod Drive (Cooling) | Yes | No credit taken for reflood, but is desirable. |
| 17. | Reactor Water Cleanup* | Yes | Not required during and immediately following an accident. Necessary in long term recovery. |
| 18. | Radwaste Collection | No | Not required for shutdown. |
| 19. | Recirculation System | No | Not required for J-P plants because core can be cooled by nat. cir. |

*These systems (or portions of these systems) have been changed from the GE/Owner's group designation of non-essential to essential.

TABLE 2.1-1 (Continued)

| | | ESSENTIAL | COMMENTS |
|---|---|---|---|
| 20. | RHR-Shutdown Cooling* | Yes | Not ESF, but desirable to use if available. Not redundant, but safety grade. |
| 21. | RHR-Containment Spray | Yes | Necessary to control pressure. |
| 22. | RHR-Suppression Pool Cooling | Yes | Heat Sink for post-accident cooling. |
| 23. | RHR-LPCI function | Yes | Safety function. |
| 24. | RHR - Steam Condensing Function* | Yes | Used in conjunction with RCIC. |
| 25. | Drywell Cooling | No | Used only in normal operation. Desirable to keep running. |
| 26. | Demineralized Water | No | Not assumed available in ECCS analysis. |
| 27. | Condensate Water | Yes | Not assumed available in ECCS analysis, but is used in RCIC and HPCS. |
| 28. | Fuel Pool Cooling | No | Boiling O.K., but make-up is necessary. Heat exchangers cooled by NCCW system. |
| 29. | Traversing In-Core Probe (TIP) | No | Not required for reactor shutdown cooling. |
| 30. | Fire Protection System | No | Availability is necessary, as the "accident" may be the result of a fire. |
| 31. | Fire Protection System | No | Serves no purpose during and immediately after accident. Longer term availability necessary. |

*These systems (or portions of these systems) have been changed from the GE/Owners Group designation of non-essential to essential.

TABLE 2.1-1 (Continued)

| | | ESSENTIAL | COMMENTS |
|---|---|---|---|
| 32. | Safety Related Instrument Air | Yes | Use for ADS function. |
| 33. | Non-Safety Related Instrument Air | | |
| 34. | Suppression Pool Cleanup | No | Not required for reactor shutdown. |

## Item No. II.F.1

### Additional Accident-Monitoring Instrumentation

REQUIREMENT

The NUREG-0737 requirements evolved from three basic requirements in NUREG-0578 (Items 1 through 3 below) and were subsequently clarified by NRC letters dated September 27, 1979, and November 9, 1979. These letters also included additional requirement resulting in Items 4 through 6 below. A summary of these items is as follows:

1. Noble gas effluent radiological monitors;

2. Provisions for continuous sampling of plant effluents for post accident releases of radioactive iodines and particulates, and onsite laboratory facilities;

3. Containment high-range radiation monitor;

4. Containment pressure monitor;

5. Containment water level monitor; and

6. Containment hydrogen concentration monitor.

The individual requirements for each item have been omitted from this synopsis due to their length and detail required for an adequate recitation.

RESPONSE

1. High range noble gas monitors are to be added to the effluent flow paths, i.e.:

   a) main plant unit vent
   b) heater bay/turbine building vent
   c) off-gas vent

   These monitors will provide range extension to include the high level noble gas concentration in accordance with Regulatory Guide 1.97 and NUGREG-0737. Power is to be derived from the diesel backed 120V AC bus.

2. Sampling systems for the purpose of collecting radioiodines and particulate effluents are to be added to the following effluent flow paths:

a) Main Plant Unit Vent

b) Heater Bay/Tubine Building Vent

c) Off-gas Vent

These sampling systems will reflect the following design criteria to meet the intent of NUREG-0737 and Reg. Guide 1.97:

1) Collection capability up to 100 u Ci/cc of gaseous iodine and particulates.

2) Provisions to limit occupational dose to personnel through shielding and operating procedures; applicable for the sample station design, sample handling and transport operations, and analysis operations.

3) Representative sampling via guidelines of ANSI N13.1-1969.

4) Diesel backed 120V AC power.

5) Sample systems initiated by receipt of containment isolation and associated plant effluent iodine monitor signals.

6) Analysis capabilities in the TSC via multichannel analyzers and detectors to determine iodine and particulate concentrations.

3. High range gamma monitors will be added to the reactor building and to the drywell to provide conformance with NUREG-0737 Table II.F.1-3 with a range of 1 R/hr to $10^7$ R/hr and to respond to the requirements of Regulatory Guide 1.97, Revision 2.

As yet the specific monitors and manufacturer have not been selected but the data will be provided when available. However, the monitors will be installed and operable prior to plant initial criticality. They will be powered from independent 120V AC, diesel-backed buses and will be provided with continuous readout and multipoint recorders in the control room. Although the calibration procedure for the monitors will vary from model to model, it will generally be by calibration source below 10 R/hr., and by electronic signal input for ranges above 10 R/hr. Detailed calibration procedures will be provided at a later date.

Planned location of the monitors is as follows: two monitors shall be located in the drywell at approximately core midplane spread approximately 32° apart centered approximately at 225° azimuth for Unit 1, and 120° azimuth for Unit 2.

Two monitors shall be located in the Reactor Building at approximately the 689' level, and the same degree spread and azimuth as those in the drywell. Plant layout drawings will be submitted approximately six months prior to fuel load, showing specific locations of the monitors.

4. Containment Pressure Monitors are to be added in the plant design to meet NUREG-0737 and Regulatory Guide 1.97 requirements.

   Two redundant channels will be provided with 2 monitors per channel meeting the range requirements of -5 psig to 60 psig. Qualification of these channels will be in accordance with PNPP's environmental qualification program. Class 1E power is supplied to these channels. Continuous indication and recording will be provided.

5. Containment suppression pool water level monitors are to be added in the plant design to meet NUREG-0737 and Regulatory Guide 1.97 requirements.

   Two redundant channels will be provided to meet the level range requirements at 1' below ECCS Suction Line level and 6' above normal suppression pool level. Class 1E power is supplied to these channels. Continuous indication and recording will be provided.

6. Containment and drywell hydrogen monitors are to be added in the plant design to meet NUREG-0737 and Regulatory Guide 1.97 requirements.

   Two redundant channels will be provided to meet hydrogen concentration requirements (0 to 30%). These channels will also be functional from 12 psia to Containment Design pressure conditions. Four sample points (Containment Dome, Drywell Dome, Drywell, and Suppression Pool Area) are utilized for each channel. Class 1E power is supplied to these channels. Continuous indication of recording will be provided.

## Item No. II.F.2

### Inadequate Core Cooling Instruments

REQUIREMENT

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including Primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the funational 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.

RESPONSE

The Cleveland Electric Illuminating Company supports the BWR Owners' Group position that no additional instrumentation is needed to monitor inadequate core cooling at the Perry Nuclear Power Plant. Further, incore thermocouples may provide the operator with ambiguous information in the event of an accident.

CEI is involved in funding and active participation in the BWR Owners' Group subcommittee on Regulatory Guide 1.97. As part of this effort, alternative means of detection of inadequate core cooling which meet the intent of Regulatory Guide 1.97 are being investigated.

Additionally, The Cleveland Electric Illuminating Company is a member of the Licensing Review Group II (LRG-II) which is pursuing a common resolution to this issue.

## Item No. II.K.1.5

### Safety-Related Valve Position

REQUIREMENT

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

RESPONSE

Perry Nuclear Power Plant is equipped with valve position status monitoring that satisfies the requirements of Regulatory Guide 1.47 as discussed in FSAR Section 7.1. Perry Plant procedures for tagging, maintenance, and surveillance will assure verification of valve position status on the affected portions of system to verify ESF systems are functional after the performance of surveillance tests, and maintenance activities. These plant procedures will be available for review by Region III Division of Inspection and Enforcement, approximately six months prior to fuel load.

## Item No. II.K.1.10

### Safety-Related System Operability Status Assurance

REQUIREMENT

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

RESPONSE

Perry Plant procedures for removing safety-related systems from service and restoring to service will assure the operability status is known. Release of all ESF equipment from service will require Unit Supervisor's (SRO) approval. Plant procedures will include verification of operability of safety-related equipment after restoration following surveillance and maintenance activities. These procedures will be available for review by Region III Division of Inspection and Enforcement, approximately six months prior to fuel load.

## Item No. II.K.1.22

### Auxiliary Heat Removal System Procedures

REQUIREMENT

For boiling water reactors, describe automatic and manual actions for proper functioning of auxiliary heat removal systems when FW system is not operable.

RESPONSE

Initial Core Cooling

Following a loss of feedwater and reactor scram, a low reactor water level signal (level 2) will automatically initiate high pressure core spray (HPCS) and reactor core isolation cooling (RCIC) systems. These systems operate in the reactor coolant make up injection mode to inject water into the vessel until a high water level signal (level 8, trips the system.

Following a high reactor water level 8 trip, the HPCS System will automatically re-initiate when reactor water level decreases to low water level 2. The RCIC System will automatically re-initiate after a high water level 8 trip. (See response to II.K.3.13).

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

The RCIC System suction is automatically transferred from the CST to the suppression pool, when the CST low level is reached. The operator can manually initiate the HPCS and RCIC Systems from the control room before the level 2 automatic initiation level is reached. The operator has the option of manual control after automatic initiation and can maintain reactor water level by throttling system flow rates. The operator can verify that these systems are delivering water to the reactor vessel by:

a. Verifying reactor water level increases when systems initiate.

b. Verify systems flow using flow indicators in the control room.

c. Verify system flow is to the reactor by checking control room position indication of motor-operated valves. This assures no diversion of system flow to the reactor.

Therefore, the HPCS and RCIC can maintain reactor water level at full reactor pressure and until pressure decreases to where low pressure systems such as Low Pressure Core Spray (LPCS) or Low Pressure Coolant Injection (LPCI) can maintain water level.

Steam Condensing

This mode of RHR operation is manually initiated. Reactor pressure provides the head to supply steam to the RHR (A or B) heat exchangers via the RCIC steam lines. In the RHR heat exchangers, the steam is condensed by Emergency Service Water passing through the heat exchanger tubes. The condensate can be sent either to the suppression pool or the suction of the RCIC pump to maintain reactor vessel level. This mode of reactor water cooling is used to maintain the reactor in either a hot standby condition or to take it to a cold shutdown condition.

Containment Cooling

After reactor scram and isolation and establishment of satisfactory core cooling, the operator would start containment cooling. This mode of operation removes heat resulting from safety relief valve (SRV) discharge and RCIC turbine exhaust to the suppression pool. This would be accomplished by placing the Residual Heat Removal (RHR) System in the containment (suppression pool) cooling mode, i.e., RHR suction from and discharge to the suppression pool.

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

a. Verifying RHR and Emergency Service Water (ESW) system flow using system control room flow indicators.

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

c. On branch lines that could divert flow from the required flow paths, close the motor-operated valves and note the effect on RHR and ESW flow rate.

Even though the RHR is in the containment cooling mode, core cooling is its primary function. Thus, if a high drywell pressure signal or low reactor water level is received at any

time during the period when the RHR is in the containment cooling mode, the RHR system will automatically revert to the LPCI injection mode. The Low Pressure Core Spray (LPCS) system would automatically initiate and both the LPCI and LPCS systems would inject water into the reactor vessel if the reactor pressure is below system discharge pressure.

Extended Core Cooling

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

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

## Item No. II.K.1.23

### Reactor Vessel Level Instrumentation

REQUIREMENT

For boiling water reactors, 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

Reactor vessel water level control room indication is continuously provided by 5 sets (range) of level monitors for normal, transient and accident conditons. Those monitors used to provide automatic safety equipment initiation are arranged in a redundant array with two instruments in each of two or more independent electronic divisions.

a. Shutdown water-level range: 1 channel with level indicator in the control room is used to monitor reactor-water level during the shutdown condition when the reactor system is flooded for maintenance and head removal. The instrument is calibrated for 120°F at 0 psig in the vessel and 80°F in the drywell. The reactor vessel nozzle taps utilized for this channel are at the 518" Vessel Level and at the top of the Head Spray flange (856" Level).

b. Upset water-level range: 1 channel with level recorder in the control room is utilized to provide water level indication extended above the upper range of the narrow-range water level monitors. The instrument is calibrated for saturated water and steam conditions at 1025 psig in the vessel and 135°F in the drywell. The reactor vessel nozzle taps utilized for this range are identical to the shutdown water level monitor.

c. Narrow water-level range: 3 channels with 3 level indicators and 1 recorder in the control room are utilized by the feedwater control system and reactor plant safeguards. The instruments are calibrated for saturated water and steam conditions at 1025 psig in the vessel and 135°F in the drywell. Water level switch trip uncertainty is ±1.5" of water level at calibration conditions. These monitors utilize the reactor vessel nozzle taps at the 518" and 606" levels.

d. Wide water-level range: 3 channels with 2 level recorders and 1 level indicator in the control room are provided for reactor plant safeguards to monitor vessel water level using the 364" and 606" level reactor vessel taps. The instruments are calibrated for 1025 psig in the vessel, 135°F in the drywell, and 20 BTU/lb subcooling below the 518" level reactor vessel nozzle tap and saturated water and steam conditions above this tap with no jet pump flow. Water level switch trip uncertainity is ±6" of water level at calibration conditions.

e. Fuel zone, water-level range: 2 channels with one level indicator and one recorder are utilized to provide water level indication above the top of the active fuel elements to below the bottom of the fuel elements. The reactor vessel nozzle taps utilized are the 606" level and jet pump diffuser level (162.8") taps. The instruments are calibrated for saturated water and steam conditions 0 psig in the vessel and the drywell with no jet pump. Water level indication uncertainty is ±6" of water level at calibration conditions.

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

Reactor Core Isolation Cooling System (RCIC)
High Pressure Core Spray System (HPCS)
Low Pressure Core Spray System (LPCS)
Residual Heat Removal/Low Pressure Injection (RHR/LPCI)
Automatic Depressurization System (ADS)
Nuclear Steam Supply Shutoff System (NS)
Standby Service Water System (SSW)

All systems automatically initiate on low reactor water level. In addition, the RCIC and HPCS systems shutdown on high reactor water level. The HPCS system automatically restarts if low reactor level is reached again. In the case of RCIC, manual resetting is required if the high reactor vessel water level trip is reached.

Additional instrumentation which the operator can use to determine changes in reactor coolant inventory or other abnormal conditions are:

Drywell High Pressure
Containment High Radioactivity Levels
Suppression Pool High Temperature

Safety Relief Valve (SRV) Discharge High Temperature
High/Low Feedwater Flow Rates
High/Low Main Steam Flow
High Containment, Steam Tunnel, and Equipment Area Differential Temperatures
High Differential Flow-Reactor Water Cleanup System
Abnormal Reactor Pressure
High Suppression Pool Water Level
High Drywell and Containment Sump Fill and Pumpout Rate
Valve Steam Leakoff High Temperatures
Low RCIC Steam Supply Pressure
High RCIC Steam Supply Flow
Low Main Steam Line Pressure

An example of the use of this additional information by the operator is as follows: Drywell high pressure is an indirect indication of coolant loss. Coincident high suppression pool temperature further verifies a loss of reactor coolant. High SRV discharge temperature would pinpoint loss of coolant via an open valve.

Other instrumentation that can signal abnormal plant status but does not necessarily indicate loss of coolant are:

High Neutron Flux
High Process Monitor Radiation Levels
Main Turbine Status Instrumentation
Abnormal Reactor Recirculation Flow
High Electrical Current (Amperes) to Recirc Pump Motors

Operators will be instructed in use of other available information to initiate safety systems as a continuing part of training.

Additional control room indication as a result of Reg. Guide 1.97 evaluations will be addressed in a later amendment.

## Item No. II.K.3.3

### Reporting Safety and Relief Valve Failures Promptly and Challenges Annually

REQUIREMENT

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

RESPONSE

Subsequent to fuel load all future main steam line relief valve challenges and failures will be reported to the NRC. This will include the prompt reporting of failures through Unusual Event Reports and the reporting of challenges in the annual report.

## Item No. II.K.3.13

### Separation of HPCI and RCIC System Initiation Levels

REQUIREMENT

Currently, the reactor core isolation cooling (RCIC) system and the high pressure coolant injection (HPCI) system both initiate on the same low water level signal and both isolate on the same high water level signal. The HPCI system will restart on low water level, but the RCIC system will not. The RCIC system is a low-flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a high 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

CEI has endorsed the position of the BWR Owners' Group delineated in the letter from Mr. R. H. Buchholz to Mr. D. G. Eisenhut dated October 1, 1980. That position is basically that "...the current design is satisfactory, and a significant reduction in thermal cycles is not necessary;" and "...no significant reduction in thermal cycles is achievable by separating the setpoints."

Modification of the initiation logic for automatic restart of the RCIC system on low water level is being incorporated into the Perry design and will be incorporated in a later FSAR amendment.

## Item No. II.K.3.15

### Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC

REQUIREMENT

The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe break detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies start-up 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.

RESPONSE

The BWR Owners' Group has evaluated this issue and has recommended the addition of a time delay to the HPCI/RCIC break detection circuitry. CEI has contracted with General Electric to provide this change to the RCIC steam line break detection circuitry. A description of this change will be included in a later FSAR amendment.

## Item No. II.K.3.16

### Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification

REQUIREMENT

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

1. Additional anticipatory scram on loss of feedwater,
2. Revised relief valve actuation setpoints,
3. Increased emergency core cooling (ECC) flow,
4. Lower operating pressures,
5. Earlier initiation of ECC systems,
6. Heat removal through emergency condensers,
7. Offset valves 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 safety/relief valves (SRVs), consistent with the ASME Code,
9. Increasing high steam line flow setpoint for main steam line isolation valve (MSIV) closure,
10. Lowering the pressure setpoint for MSIV closure,
11. Reducing the testing frequency of the MSIVs,
12. More stringent valve leakage criteria, and
13. Early removal of leaking valves.

An investigation of the feasiblity 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).

RESPONSE

The Cleveland Electric Illuminating Company has participated in a BWR Owners' Group evaluation of possible ways to reduce the challenges and failures of safety relief valves. The results of this feasibility study were submitted to the NRC in a letter from D. B. Waters to D. G. Eisenhut dated March 31, 1981. The study concluded that BWR/6 plants already include design features which significantly reduce the likelihood of stuck open relief valve (SORV) events; no further design modifications are necessary. It is The Cleveland Electric Illuminating Company's position that further modifications to the Perry Nuclear Power Plant would not significantly reduce the frequency of SORV events.

## Item No. II.K.3.17

Report on Outages of Emergency Core-Cooling Systems Licensee Report and Proposed Technical Specification Changes

### REQUIREMENT

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

### RESPONSE

The Cleveland Electric Illuminating Company commits to reporting a summary of emergency core cooling system outages annually.

## Item No. II.K.3.18

Modification of Automatic Depressurization System Logic - Feasibility for Increased Diversity for Some Event Sequences

### REQUIREMENT

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

### RESPONSE

Cleveland Electric Illuminating Company has participated in the BWR Owner's Group evaluation of logic modifications to simplify ADS actuation. The results of this study were submitted to the NRC in a letter from D. B. Waters to D. G. Eisenhut dated March 31, 1981. The BWR O/G is presently reevaluating the recommendations due to recently identified conflicts between the proposed modifications to ADS actuation logic and the Emergency Procedures Guidelines. As discussed in a February 5, 1982 letter from T. J. Dente to D. G. Eisenhut, the BWR O/G will provide a supplement to the original owner's group report by September 30, 1982.

Subject to the recommendations at the BWR O/G report, CEI will implement prior to fuel load, one of the two alternative modifications to the ADS actuation logic, acceptable to the NRC. The first alternative consists of bypassing the high drywell pressure trip used for ADS initiation if the reactor vessel water level remains below the low pressure ECCS setpoint for a sustained period. The other alternative involves elimination of the high drywell pressure trip.

CEI is participating in the O/G reevaluation effort and will document the final resolution of this item in a future amendment.

## Item No. II.K.3.21

### Restart of Core Spray and Low Pressure Coolant-Injection Systems

REQUIREMENT

The core spray and low pressure coolant injection (LPCI) system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart, if required, to ensure 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.

RESPONSE

The Cleveland Electric Illuminating Company endorses the BWR Owners' Group position in the letter from D. B. Waters to D. G. Eisenhut dated December 29, 1980. That position is the current LPCI, LPCS, and HPCS system designs are adequate and no design changes are required.

Originally, a modification was planned for the HPCS system as discussed in the LRG-II position paper for issue 1-RSB. This automatic reset modification of the HPCS would reset the auto-initiation signal for low water level and block the continuing auto-initiation signal for high drywell pressure to allow auto-restart of HPCS pump on low water level after the operator stopped the HPCS pump. Decrease in drywell pressure below trip level returns HPCS logic to original status.

However, the NRC current position, identified in a letter from J. R. Miller to D. L. Holtzacher dated February 26, 1982 is that the automatic restart of HPCS after manual termination is optional and not necessarily required. The following justification is provided for not modifying the HPCS logic. A revised LRG-II position will be submitted to reflect this justification.

Immediately following a LOCA that produces either high drywell pressure or low reactor water level, the HPCS will automatically start. Injection of emergency cooling water into the reactor will occur. Flow from the high pressure core spray system is automatically terminated when the reactor water level reaches its high level trip point (Level 8). This control feature prevents unnecessary flooding of the reactor vessel and steamlines. Termination of HPCS injection can occur either automatically or by operator action. In the event of the former, the HPCS system will restart automatically if and when reactor water level decreases from the

high level trip point to the low level initiation setpoint. For the latter event, a manual action is required to restart HPCS. It was the NRC's concern for reliance upon the operator to restart the HPCS after manual termination that prompted the proposed design modification. Such a modification is not necessary for the following reasons:

1. The ECCS logic design which permits operator intervention is based on a legitimate assumption that the operators are not likely to prematurely terminate ECCS flow and thereby jeopardize the core cooling process. In actual practice, one of the highest priority activities for an operator in an accident situation is to assure that emergency systems have started correctly and are effectively maintaining core coverage. This guidance is provided to the operator through the plant's emergency operating procedures.

   If the operator should terminate HPCS system flow, such termination would be based on event-specific conditions, such as:

   (A) Adequate coolant flow from other systems (Feedwater, RCIC) is available,

   (B) HPCS system equipment problems (gross seal leakage, pipe breaks, equipment flooding),

   (C) Required vessel coolant makeup rate much less than HPCS system capability (6000 gpm) and well within RCIC system capability (600 gpm).

2. For the long-term core cooling situation, the plant operators manually set up the auxiliary systems to support eventual termination of the incident. Consequently, adequate core cooling is dependent upon correct operator actions. Such actions are not constrained by strict time requirements. This aspect of ECCS design is considered fully acceptable because of the time available between attaining Level 1 and the occurrence of high fuel clad temperatures.

3. A key incentive of vessel water level control is to keep the core covered but also to prevent water level from reaching Level 8 where in addition to HPCS, the RCIC and feedwater systems (if operating) would be tripped off.

4. Automatic vessel water level control will be available from the RCIC system. This system will be capable of automatic restart on Level 2 after automatic termination at Level 8 as provided for in response to TMI Action Plan Item II.K.3.13.

5. Inadequate core cooling as a result of the operator failing to reinitiate the HPCS system would not occur because eventually the ADS initiation level would be reached. This would result in reactor blowdown and core flooding by the low pressure ECCS.

The manual override option is deliberate and is considered to be an important safety feature of the BWR ECCS network. This feature provides the plant operators with flexibility for dealing with unforeseen but credible conditions requiring a particular system to be shut down. This option, complemented by the other means available to automatically maintain adequate core cooling, provides adequate justification for not implementing the HPCS system automatic restart after manual termination modification.

## Item No. II.K.3.22

Automatic Switchover of Reactor Core Isolation Cooling System Suction -- Verify Procedures and Modify Design

### REQUIREMENT

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

### RESPONSE

The RCIC pump suction is provided with automatic switchover from condensate storage tank to suppression pool, as described in Perry FSAR Section 7.4.1.1 (Page 7.4-3).

## Item No. II.K.3.24

Confirm Adequacy of Space Cooling for High-Pressure Coolant Injection and Reactor Core Isolation Cooling Systems

### REQUIREMENT

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

### RESPONSE

PNPP utilizes safety-related pump rooms cooled by unit coolers and support systems designed to withstand the consequences of a complete loss of offsite AC power. Loss of offsite AC power results in power being supplied from the engineered safety features bus. Refer to Subsection 9.4.5 for a further discussion of engineered safety features ventilation systems.

## Item No. II.K.3.25

### Effect of Loss of Alternating-Current Power on Pump Seals

REQUIREMENT

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

RESPONSE

The Cleveland Electric Illuminating Company has participated in the BWR Owners' Group evaluation of the effect of the loss of pump seal cooling for a period of 2 hours. This evaluation was submitted in a letter from D. B. Waters to D. G. Eisenhut, dated May 1981. The study indicates that the loss of pump seal cooling for 2 hours is not a safety problem, but may require seal repairs prior to resuming operating. Even in the case of both seal cooling systems failing, followed by extreme degradation of the pump seals, the primary coolant loss is analyzed to be less than 70 gallons per minute. Consequently, no hazard to the health and safety of the public will result from total loss of recirculation pump seal cooling water.

In addition, a supplement of the BWR Owner's Group evaluation was submitted in a letter from T. J. Dente to D. G. Eisenhut dated September 21, 1981. This supplement describes three tests performed on Representative BWR reactor recirculation pumps in which all seal cooling water was lost. The test results show that pump seal leakage is acceptably low following a loss of seal cooling water for as long as two hours. These test results are representative and bounding for the Byron Jackson reactor recirculation pumps utilized at Perry.

## Item No. II.K.3.27

### Provide Common Reference Level for Vessel Level Instrumentation

REQUIREMENT

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.

RESPONSE

The Cleveland Electric Illuminating Company, as a member of the Licensing Review Group II (LRG-II), submitted the position paper dated November 20, 1981, which addressed this item.

LRG-II plants use the bottom of the dryer skirt as the reference point for all RPV level instruments. Only one instrument requires a scale modification to meet this requirement: the fuel zone level indicators. The LRG-II position is to provide a fuel zone level instrument with two scales. One scale will be referenced to the bottom of the dryer skirt and the second scale referenced to the top of the fuel.

In addition, the common reference level and fuel zone level indicators will be incorporated in operator training, training documents and maintenance procedures for Perry.

## Item No. II.K.3.28

### Verify Qualification of Accumulators on ADS Valves

REQUIREMENT

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 the ECC systems are designed to withstand a hostile environment and still perform their function 100 days after an accident. The Licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee must show that the accumulator design is still acceptable.

RESPONSE

The ADS accumulators are designed to provide two S/RV actuations at 70% of drywell design pressure, which is equivalent to 4 actuations at atmospheric pressure. The ADS valves are designed to operate at 70% of drywell design pressure because that is the maximum pressure for which rapid reactor depressurization through the ADS valves is required. The greater drywell design pressures are associated only with the short duration primary system blowdown in the drywell immediately following a large pipe rupture for which ADS operation is not required. For large breaks which result in higher drywell pressure, sufficient reactor depressurization occurs due to the break to preclude the need for ADS. One ADS actuation at 70% of drywell design pressure is sufficient to depressurize the reactor and allow inventory makeup by the low pressure ECC systems. However, for conservatism, the accumulators are sized to allow 2 actuations at 70% of drywell design pressure.

The ADS accumulators and piping from the receiver tanks are ASME Section III, Class 3 safety grade components. The pneumatic supply system for the ADS accumulators is provided by the safety-related instrument air system, described in FSAR Section 6.8.

## Item No. II.K.3.30

### Revised Small-Break Loss-of-Coolant-Accident

### Methods to Show Compliance with 10CFR Part 50, Appendix K

REQUIREMENT

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

RESPONSE

The General Electric Company has evaluated the NRC request to demonstrate the BWR small-break LOCA analysis methods are in compliance with Appendix K to 10CFR Part 50. Documentation that GE's present analytical methods are acceptable was provided in a letter from R. H. Buckholz, GE to D. G. Eisenhut dated June 26, 1981.

## Item No. II.K.3.31

### Plant-Specific Calculations to Show Compliance with 10CFR Part 50.46

REQUIREMENT

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) as described in Item II.K.3.30 to show compliance with 10CFR 50.46 should be submitted for NRC approval by all licensees.

RESPONSE

The results of a typical LOCA analysis have been provided in FSAR Section 6.3.3. This analysis uses the currently approved Appendix K methodology. A Perry Plant specific analysis using NRC approved models will be submitted in April 1982. If any model changes are required by the NRC as a result of Item II.K.3.30, an evaluation will be made of the impact of the change on the Perry plant specific analysis, to determine the need for any additional analysis.

## Item II.K.3.44

### Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure

REQUIREMENT

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

RESPONSE

The Cleveland Electric Illuminating Company jointly sponsored, through the BWR Owners Group, an evaluation of the worst anticipated transient (loss of feedwater event) with the worst single failure (loss of a high pressure inventory makeup or heat removal system) to demonstrate adequate core cooling capability. These results were submitted to the NRC via a letter from D. B. Waters, Chairman BWR Owners Group, to D. G. Eisenhut, Director NRC, dated December 29, 1980. NRC memorandum "Evaluation of BWR Owners Group Generic Response to NUREG-0737, Item II.K.3.44 dated May 19, 1981," from P. S. Check (NRC) to G. Lainas (NRC) found this report acceptable to be referenced by individual licensees/ applicants. A summary of the results of the analysis follows:

The anticipated transients in NRC Regulatory Guide 1.70, Revision 3 were reviewed for all BWR product line BWR/2 through BWR/6 from a core cooling viewpoint. The loss of feedwater event was identified to be the most limiting transient which would challenge core cooling. The BWR/6 is designed so that the HPCS or ADS with subsequent low pressure makeup is independently capable of maintaining the water level above the top of the active fuel given a loss of feedwater. The detailed analysis shows that even with the worst single failure in combination with the worst transient the core remains covered.

Furthermore, even with degraded conditions involving one SORV in addition to the worst transient with the worst single failure, studies show that the core remains covered during the whole course of the transient either due to RCIC operation or due to automatic depressurization via the ADS or manual depressurization by the operator so that low pressure inventory makeup can be used.

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

## Item No. II.K.3.45

### Evaluation of Depressurization with Other Than ADS

REQUIREMENT

Analyses to support depressurization modes other than full actuation of the automatic depressurization system (ADS) [e.g., early blowdown with one or two safety relief valves (SRVs)] should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

RESPONSE

The Cleveland Electric Illuminating Company participated in the BWR Owners' Group generic evaluation of alternate modes of depressurization other than full actuation of the ADS. The results of this program were submitted to the NRC in a letter from D. B. Waters to D. G. Eisenhut dated December 29, 1980. The BWR Owners' Group evaluation showed that vessel integrity limits are not exceeded for full blowdown, and slower depressurization rates have little benefit to vessel fatigue.

## Item No. II.K.3.46

### Michelson Concerns on the Importance of Natural Circulation During a Very Small Break LOCA and Other Related Items

REQUIREMENT*

A number of concerns related to decay heat removal following a very small break LOCA and other related items were questioned by Mr. C. Michelson of the Tennessee Valley Authority. These concerns were identified for PWRs. GE was requested to evaluate these concerns as they apply to BWRs and to assess the importance of natural circulation during a small-break LOCA in BWRs. GE has not yet responded to the Michelson concerns. A brief description of natural circulation was addressed in NEDO-24708. The submittal was incomplete, however, in that natural circulation for purpose of depressurizing the reactor vessel was not addressed. GE should provide a response to the Michelson concerns as they relate to BWR plants.

RESPONSE

General Electric Company has provided a response to the questions posed by Mr. C. Michelson as they relate to BWR plants. These responses were prepared on behalf of the BWR Owners Group and issued in a letter to Mr. D. F. Ross of the NRC from R. H. Buchholz of GE dated February 21, 1980, and titled "Response to Questions Posed by Mr. C. Michelson."

*This REQUIREMENT is taken from NUREG-0626 since it is not provided in detail in either NUREG-0660 or NUREG-0737.

## Item No. III.A.1.1

### Upgrade Emergency Preparedness

REQUIREMENT

Comply with Appendix E, "Emergency Facilities," to 10CFR Part 50, Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and for the offsite plans, meet essential elements of NUREG-75/111 (Ref. 28) or have a favorable finding from FEMA.

RESPONSE

The Cleveland Electric Illuminating Company submitted Amendment 2 to the Perry Nuclear Power Plant (PNPP) Emergency Plan on May 22, 1981. The upgraded Emergency Plan appears as Appendix 13A of the PNPP FSAR.

## Item III.A.1.2

### Upgrade Emergency Support Facilities

REQUIREMENT

Establish an interim onsite technical support center separate from, but close to, the control room for engineering and management support of reactor operations during an accident. The center shall be large enough for the necessary utility personnel and five NRC personnel, have direct display or callup of plant parameters, and dedicated communications with the control room, the emergency operations center, and the NRC. Provide a description of the permanent technical support center.

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

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

These requirements shall be met before fuel loading. See NUREG-0578, Sections 2.2.2.b, 2.2.2 c (Ref. 4), and letters of September 27 (Ref. 23) and November 9, 1979, (Ref. 24) and April 25, 1980, (Ref. 29).

RESPONSE

The Cleveland Electric Illuminating Company will establish a Technical Support Center (TSC), an Operational Support Center (OSC), and an Emergency Operations Facility (EOF) to satisfy the intent of NUREG-0696, "Functional Criteria for Emergency Response Facilities." These support facilities will be completed prior to fuel load.

The TSC will occupy about 5,000 square feet at the 603'-6" elevation of the Service Building. The OSC will be located in Room 599-05 at the 599'-0" elevation of the Control Complex. Communication will be provided with the TSC and Control Rooms. The location and design of a near site EOF are now in the planning stage.

Further descriptions of these emergency support facilities can be found in Section 7.0, "Emergency Facilities and Equipment" of Appendix 13A to the FSAR.

## Item No. III.D.1.1

### Integrity of Systems Outside Containment Likely to Contain Radioactive Material

REQUIREMENT

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

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.

RESPONSE

The Cleveland Electric Illuminating Company will establish a program of leak testing Class I, II and III Systems that will satisfy the requirements of ASME Section XI, "In-Service System Pressure Tests." The testing will be performed on a schedule appropriate for 10CFR50 App. J. Type B and C tests, that is at each refueling outage. Leakage paths discovered during these tests will be investigated and when necessary maintenance work requests will be prepared to initiate work to reduce leakage to its lowest practical level.

## Item No. III.D.3.3

### Improved Inplant Iodine Instrumentation Under Accident Conditions

REQUIREMENT

a. Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

b. Each applicant for a fuel loading license to be issued prior to January 1, 1981, shall provide the equipment, training and procedures necessary to accurately determine the presence of airborne radio-iodine in areas within the plant where plant personnel may be present during an accident.

RESPONSE

Fixed continuous air monitors and portable air monitors and air samplers are utilized to determine the concentrations of airborne radioactivity throughout the plant.

The fixed air monitors, described in Section 12.3.4 provide continuous data to indicate trends throughout the various plant areas. Particulate filters and charcoal cartridges are removed periodically to identify the specific nuclides encountered.

Portable air samplers are used to collect particulate and charcoal grab samples of areas of specific concern, for example, in preparation and conduct of specific work functions, to verify significant indicated changes by one or more fixed air monitors, or periodic air sampling throughout the plant.

In plant iodine analysis under accident conditions is accomplished by collection of iodine samples utilizing Silver Zeolite Iodine Sampling cartridges. The cartridges and filters are analyzed by gamma spectroscopy using computer anaysis techniques.

An Emergency Plan implementing procedure will be prepared to address sampling and appropriate personnel (Radiation Monitoring team members and Shift Health Physics Technicians) will be trained in these procedures.

Flushing of iodine cartridges to reduce noble gas interference is accomplished with service air available in a hood in the Low Level Laboratory.

FSAR Table 12.5-4 lists the quantities of air samplers available. FSAR Table 12.3-10 lists the Airborne Radiation Monitors.

## Item No. III.D.3.4

### Control-Room Habitability Requirements

REQUIREMENT

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

RESPONSE

This requirement has been met for PNPP as detailed within the FSAR. Section 6.4 fully describes the control HVAC system layout and functional design including protection of the control room from toxic and radioactive gases. Subsection 2.2.3 reports the results of the evaluation of potential accidents involving non-radioactive hazardous materials including gaseous fuels, liquified gases, explosives and toxic chemicals.

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