LONG ISLAND LIGHTING COMPANY
SHOREHAM NUCLEAR POWER STATION
P.O. BOX 618, NORTH COUNTRY ROAD • WADING RIVER, N.Y. 11792

April 15, 1981 SNRC-557

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Shoreham Nuclear Power Station - Unit 1
Docket No. 50-322

Dear Mr. Denton:

Forwarded herein are fifteen (15) copies of our positions related to Post-TMI Requirements outlined in NUREG-0737. These requirements were transmitted via letter dated October 31, 1980 from Mr. Darrell G. Eisenhut. Where applicable, our responses to certain NUREG-0578 items (SNRC-503, dated August 29, 1980) are superceded by the respective responses contained herein.

The positions included in this submittal are listed in Attachment 1. The present schedule for submittal of the remaining items is as shown in Attachment 2. This information will be contained in a future amendment to the FSAR.

Please note that regarding our response to NUREG-0737, item II.K.3.27, Common Water Level Reference, we are in receipt of and presently assessing your letter from Mr. D. Eisenhut to Mr. D. B. Waters, Chairman, BWR Owners Group, dated April 6, 1981.

Very truly yours,

J. P. Novarro

J. P. Novarro
Project Manager
Shoreham Nuclear Power Station

RWG:mp

cc: J. Higgins



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ATTACHMENT 1

| | |
|---|---|
| I.A.1.1 | Shift Technical Advisor |
| I.A.2.3 | Administration of Training Programs |
| I.C.2 | Shift and Relief Turnover Procedures |
| I.C.4 | Control Room Access |
| I.C.5 | Procedures for Feedback of Operating Experience to Plant Staff |
| II.D.3 | Relief and Safety Valves Position Indication |
| II.E.4.1 | Containment Dedicated Penetrations |
| II.K.1.5 | Safety-Related Valve Position |
| II.K.3.15 | Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems |
| II.K.3.17 | Report on Outage of ECC Systems - Licensee Report and Proposed Technical Specification Changes |
| II.K.3.21 | Restart of Core Spray and LPCI Systems on Low Level |
| II.K.3.22 | Automatic Switchover of Reactor Core Isolation Cooling System Suction - Verify Procedures and Modify Design |
| II.K.3.27 | Provide Common Reference Level for Vessel Level Instrumentation |
| II.K.3.28 | Study and Verify Qualification of Accumulators on ADS Valves |
| II.K.3.44 | Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure |
| II.K.3.45 | Evaluation of Depressurization with Other Than Full ADS |
| II.K.3.46 | Response to List of Concerns From ACRS Consultant |

ATTACHMENT 2

Items scheduled for submittal on 5/15/81

| | | |
|---|---|---|
| I.A.1.2 | II.B.2 | II.K.3.16 |
| 1.A.1.3 | II.B.3 | II.K.3.18 |
| I.A.2.1 | II.B.7 | II.K.3.24 |
| I.A.3.1 | II.F.1 | II.K.3.25 |
| I.C.1 | II.K.1.22 | III.A.1.1 |
| I.C.7 | II.K.1.23 | III.A.2 |
| I.C.8 | II.K.3.3 | III.D.3.3 |
| I.D.1 | II.K.3.13 | III.D.3.4 |
| | II.F.2 | |

Items scheduled for submittal on 5/30/81

| | | |
|---|---|---|
| I.B.1.2 | II.B.1 | II.K.1.10 |
| I.C.3 | II.B.4 | II.K.3.30 |
| I.C.6 | II.D.1 | II.K.3.31 |
| I.D.2 | II.E.4.2 | III.A.1.2 |
| I.G.1 | II.F.3 | III.D.1.1 |

# INTRODUCTION

This section contains the Shoreham positions for the TMI Action Plan Requirements of NUREG-0737.

The entire position for each item is provided in this section except in certain limited cases where figures from other sections are referenced. In some cases, the position stated in this section supersedes other sections of the FSAR. All sections of the FSAR will be revised to be consistent with these positions but to the extent that inconsistencies may exist, this section governs.

## I.A.1.1 SHIFT TECHNICAL ADVISOR

NRC Position

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

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

LILCO Position

LILCO will provide an on-shift (technical) advisor to the Watch Engineer provided the Watch Engineer is not fully qualified per FSAR Section 13.1.3.1.16. The STA will be available within 10 minute notification. The STA will have a bachelor's degree in a scientific or an engineering discipline or equivalent. The STA will receive the following training:

- basic nuclear theory
- basic reactor theory
- basic health physics and shielding theory
- thermodynamics
- fluid dynamics
- heat transfer
- BWR nuclear engineering (including chemistry, instruments, and controls)
- plant systems training
- accident/transient analysis
- management and behavioral theory

Certain portions of this training program may be waived for personnel who demonstrate adequate understanding of the required subject matter by examination of by experience. Such waivers will be granted in writing.

The STA's primary responsibility will be to advise the Watch Engineer in the event of an accident or transient. The STA will be assigned other engineering duties which are compatible with his primary responsibility. Included in these additional engineering duties may be:

- participation in an on-site safety review group
- evaluation of effectiveness of plant emergency and operating procedures in terms of terminating or mitigating accidents
- periodic evaluation and review of plant instructions and emergency procedures
- evaluation of core power distribution and thermal limits
- evaluation of NRC Licensee Event Reports

## I.A.2.3 Administration of Training Program

NRC Position

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

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

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

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

LILCO Position

It is LILCO's position that permanent members of the training staff who teach systems, integrated responses, or transients be qualified or certified to teach in the appropriate subject area.

The qualification or certification of permanent members of the training staff may be accomplished by one or more of the following:

1. Approval by an accredited training institution; or

2. Successful completion of an SRO certification examination on an appropriate simulator; or

3. Successful completion of an NRC SRO examination.

LILCO does not intend to rquire either guest lecturers who are experts in particular subjects (reactor theory, instrumentation, thermodynamics, health physics, chemistry, etc.) to successfully

complete an NRC SRO examination; or system experts, such as an instrument and control supervisor teaching the control rod drive system to successfully complete an NRC SRO examination.

## I.C.2 Shift and Relief Turnover Procedures

NRC Position

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 oncoming auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance of test that by themselves could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transients (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).

LILCO Position

Procedures to implement the intent of the objectives described in Action Plan Item I.C.2 are included in the Station Operating Manual. These procedures provide the means for the operating staff to possess adequate knowledge of critical plant parameter status, system status, availability, and alignment before the

watch is relieved. This is done by requiring log reviews and equipment status turnovers as a normal course of the relief process at each station.

The required changes necessary to implement fully the objectives of Action Plan Item I.C.2 will be made to existing Station Procedures prior to fuel load. These changes will provide for the required checklists or logs mentioned in items (1) and (2) above of the NRC position, as well as a system to evaluate the effectiveness of the shift and relief turnover procedures mentioned in item (3) of the NRC position.

## I.C.4 Control Room Access

### NRC Position

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

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.

### LILCO Position

A procedure to implement the intent of the objectives described in Action Plan I.C.4 is included in the Station Operating Manual. In order for the Shoreham facility to fully comply with the objectives of the Action Plan, a revision to the Station Procedure is required to include in the overall scope of this procedure the existance of both a Watch Engineer (Shift Supervisor) and a Shift Foreman, both of which hold a senior reactor operator's license and one of which will be in the control room at all times. LILCO's position is that the required revision to this procedure will be made and implemented prior to Fuel Load. The Station Procedure, along with the required changes, is outlined below as it refers to the objectives of Action Plan Item I.C.4.

### Authorization for Entry

The Station Procedure contains a section entitled "Authorization for Entry" which establishes the authority and responsibility of the Watch Engineer to limit the access to the control room to that which is consistent with plant evolutions. This section presently delegates this function to the Nuclear Station Operator (holder of a reactor operator's license and present in the control room) when the Watch Engineer is absent from the control

room. This section will be changed to give the Shift Foreman the command control function in the control room when the Watch Engineer is not in the control room.

Conduct of Personnel During Abnormal Plant Conditions

The Station Procedure also contains a section entitled "Conduct of Personnel During Abnormal Plant Conditions" which establishes a clear line of authority and responsibility in the control room in the event of an incident. This section does this by clearly defining in broad terms what actions are to be taken and who is to take them (i.e., immediate and subsequent actions, ensuring availability of an adequate heat sink to remove decay heat, safe shutdown of the main turbine and the balance of plant systems, etc) to ensure reactor safety.

This section of the Station Procedure also delineates the lines of communication and authority of plant management personnel who are not in direct command of operations (including those who report to stations outside of a control room). This is accomplished by identifying the personnel who are responsible for the actions to be taken outside of the control room and the flow of communication will be from the Equipment Operator (Auxiliary Operator in the field) to the main control room directly or through a casualty control station outside of the main control room.

This section presently requires the Watch Engineer to take charge of the incident in the control room with the Nuclear Station Operator giving him a turnover in the event he is not present in the control room when the incident initiates. Since the Nuclear Station Operator does not hold a senior reactor operator's license and since either the Shift Foreman or the Watch Engineer will be required to be in the control room at all times, this section will be changed to have the Shift Foreman assume the command control function when the incident initiates in the absence of the Watch Engineer.

## I.C.5 Procedures for Feedback of Operating Experience to Plant Staff

NRC Position

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

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

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

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

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

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

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

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

Each utility shall carry out an operating experience assessment function that will involve utility personnel having collective competence in all areas important to plant safety. In connection with this assessment function, it is important that

procedures exist to assure that important information on operating experience originating both within and outside the organization is continually provided to operators and other personnel, and that it is incorporated into plant operating procedures and training and retraining programs.

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

LILCO Position

Procedures to accomplish the general objectives of Action Plan Item I.C.5 are included in the Station Operating Manual. The procedures for the feedback of operating experience and other important information to the appropriate Shoreham personnel are outlined below.

1. Feedback of Information

The Required Reading List is a primary means for assuring that information essential to safe and reliable operation of the plant is routed to and understood by the appropriate personnel. The Required Reading List may include, but not be limited to material such as facility design changes, procedure changes, facility license changes, licence events reports, NRC I & E information notices, nuclear power experience, and NSSS and BOP equipment vendors correspondence.

The Plant Manager, Chief Operating Engineer, Chief Technical Engineer, and the Section Heads will inform the Training Supervisor of information to be placed on the Required Reading List and to which groups it should be routed. They shall determine what experiences, concerns, or other information

originating within the Shoreham facility are of sufficient importance to be included as required reading for plant personnel. Technical information coming from sources outside Shoreham is subjected to a documented and controlled technical review cycle in accordance with Shoreham station procedures. Appropriate Section Heads are assigned review responsibility of documents applicable to their area of expertise as part of the review cycle. At this time they would make a determination whether a document is to be included on the Required Reading List.

It is the responsibility of the individuals listed above to limit the materials they submit for inclusion on the Required Reading List to essential information only. They are also responsible for preventing the conveyance of conflicting or contradictory information to plant personnel before resolution is reached. The Training Supervisor, who performs the actual documentation, control and routing of the list, will serve as a backup check to prevent the routing of extraneous or contradictory materials.

Normal routing in accordance with Shoreham station procedure gives all personnel on the list the opportunity to read and understand the material within 30 days, by which time it should be returned to the Training Supervisor. The Training Supervisor is charged with the responsibility of assuring that the Required Reading List is completed in a timely manner. The procedure also allows for alternate methods, such as supervisor lectures, staff meetings, preplanned lectures, etc., for the expeditious preparation of certain information requiring the special attention of station personnel.

2. Training Revisions

The Training Supervisor is responsible for coordinating the preparation and revision of training programs and lesson plans in accordance with Shoreham station procedures. Section Heads provide recommendations and other input information to the Training Supervisor for the updating of training programs in their section's area of responsibility. At such time they would recommend revision to incorporate the most recent operating experience or other important information into the lesson plans. This material may also be inlcuded in quizzes or exams as a check to assure the effectiveness of the operating experience feedback process.

3. Station Procedures Revision

A Section Head, Chief Engineer, or the Plant Manager may determine the need for revising an existing procedure or adding a new procedure based on pertinent operating experience assessments, NRC correspondence, manufacturers recommendations, or other applicable information. Shoreham station procedures clearly define the methodology for achieving this objective.

4. Review of Operating Experience

The review of plant operating experience at the Shoreham facility is a continuing function of the Review of Operations Committee (ROC). The committee includes the Plant Manager as Chairman, the Chief Operating Engineer and Chief Technical Engineer as Vice-chairmen, and the various Section Heads as regular members. ROC advises the Plant Manager on all matters related to past, present and future operation and all matters related to public safety. The Review of Operating Committee is an essential part of the plant review and audit program. It ensures that operation is in conformance with the established operating procedures, license provisions, and quality requirements; it reviews changes in procedures, and changes in technical specifications which may constitute an unreviewed safety question as defined in 10CFR Part 50.59. A continuing effort is performed by the Review of Operations Committee to direct and monitor plant operation, and to plan future activities.

## II.D.3 Relief and Safety Valves Position Indication

### NRC Position

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

The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken. The valve position should be indicated in the control room and an alarm should be provided in conjunction with this indication.

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

The valve position indication should be seismically qualified consistent with the component or system to which it is attached. It also should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with Commission Order, May 23rd, 1980 (CLI-80-21).

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

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

integration into emergency procedures,

integration into operator training, and

other alarms during emergency and need for prioritization of alarms.

### LILCO Position

There are a total of eleven (11) dual function safety relief valves (SRV) in the Shoreham Reactor System. The SRVs

installed in this facility are of the Target Rock two-stage pilot operated design. Direct main stem position indication is not accessible in a valve of this type. Accordingly, positive position indication is provided utilizing pressure transmitters on each SRV discharge line.

The discharge of each SRV is independently piped to approximately five (5) feet from the bottom of the suppression pool. The calculated steady state pressure near the valve discharge is in the range of 300 psig when the valve relieves at set pressure. This pressure is sufficiently high that a positive and unambiguous signal is available with ample margin for tolerances in calibration and variance in line pressure. When a valve recloses, pressure will return to normal in a fraction of a second. Thus, pressure measurement does not have the slow response time which characterizes discharge pipe temperature monitoring instrumentation. Since each valve discharge is independently piped, the pressure signal provides unique indication for the associated valve.

Nonredundant safety-grade instrumentation is provided to monitor pressure in the discharge pipe of each SRV. The transmitters are located in the secondary containment and connected to the SRV discharge piping by instrument lines penetrating the primary containment. Individual display and trip set point instrumentation is provided for each SRV in the main control room. The range of instrumentation allows for a trip setpoint of 10-50 percent of rated flow. This gives a positive open position indication and also provides sufficient sensitivity to detect a partially open SRV. A common alarm is also provided in the control room to promptly alert the operator when any SRV is open. The display instrumentation is located as close as possible to the SRV control station in the main control room.

In addition to being qualified for the environment expected during events resulting in SRV discharge to the suppression pool, the instrumentation meets seismic Category I requirements in accordance with IEEE 344-1971 and is powered from a Class IE power supply.

The existing temperature monitoring instrumentation is retained for its original function, detection of valve leakage conditions as backup/confirmatory indication for the pressure instrumentation.

## II.E.4.1 Containment Dedicated Penetrations

### NRC Position

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

Components furnished to satisfy this requirement shall be safety grade.

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.

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

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

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

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

LILCO Position

The Shoreham design presently incorporates redundant external recombiners for the control of combustible gases inside the primary containment.

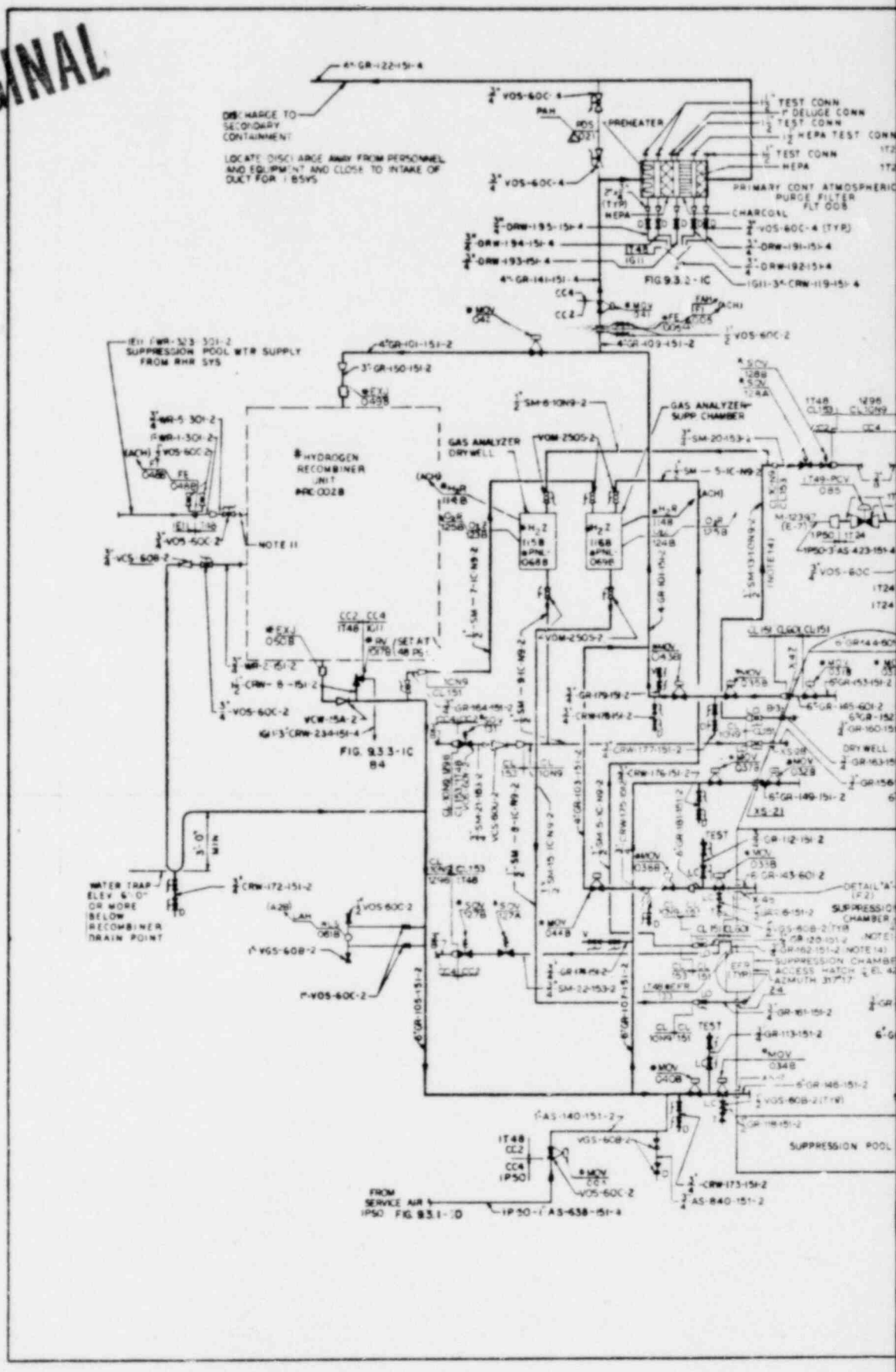
Two 100 percent capacity hydrogen recombiners are currently installed. The system is safety-related, Seismic Category I and designed in accordance with ASME III, Code Class 2. The recombiners are located in the reactor building outside the primary containment. Four dedicated penetrations are provided for each recombiner as shown in Figure 6.2.5-1.

The Primary Containment Integrated Leak Rate Test System uses the PCAC Containment Isolation System penetrations during plant shutdown. This does not degrade the PCAC Containment Isolation System, since the Integrated Leak Rate Test System is always isolated during plant operation.

Two isolation valves are provided for each primary containment penetration in accordance with the redundancy and single failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR 50. However, automatic isolation is not provided, since all isolation valves in this system are closed during normal operation.

The design is based on 10 CFR 50.44 requirements.

POOR ORIGINAL



POOR ORIGINAL

NOTES: CONT (K-2)

12. ALL LOCAL OPEN ENDED OR CAPPED (CLOSURE) VENTS, DRAINS AND TEST CONNECTIONS ON ASME III CODE CLASS 1,2 OR 3 SYSTEMS SHALL BE CONSIDERED CODE CLASS 4 DOWNSTREAM OF THE OUTERMOST BLOCK VALVE (INCLUDING WHERE APPLICABLE THE WELD ATTACHING THE OUTERMOST BLOCK VALVE WITH THE DOWNSTREAM NIPPLE OR PIPE) UNLESS OTHERWISE NOTED. THE DOWNSTREAM NIPPLE OR SHORT SECTION OF PIPE SHALL NOT BE GIVEN A SEPARATE LINE NUMBER.

NOTES:

1. ALL LINE DESIGNATION NOS. & EQUIPMENT MARK NOS. TO BE PREFIXED WITH UNIT & SYSTEM NO. (T48 UNLESS OTHERWISE NOTED) AS FOLLOWS: (T48-6-N-143-151-2.
2. ALL INSTRUMENT NOS. ARE PREFIXED BY THE UNIT & SYSTEM NO. (T48, UNLESS OTHERWISE NOTED AS FOLLOWS: (TARNOV 031A.
3. ALL CONNS FOR PRESS. INSTRUMENTS, SAMPLING AND TESTING TO BE ¾"VOS-60C-2 EXCEPT AS NOTED.
4. ALL MOTOR OPERATED VALVES (MOV) TO BE VGW-15A-2, EXCEPT AS NOTED.
5. ⊗ INDICATES "SAFETY RELATED EQUIPMENT & INSTRUMENTATION"
6. DELETED
7. * INDICATES "FURNISHED BY EQUIPMENT MANUFACTURER"
8. ALL PRIMARY CONTAINMENT PENETRATIONS ARE 6 INCHES
9. ALL VENT AND DRAIN VALVES TO BE ¾"VOS-60C-2 UNLESS OTHERWISE NOTED.
10. ALL PIPING TO BE CODE CLASS 2 UNLESS OTHERWISE NOTED
11. INTERFACE ON HYDROGEN RECOMBINER UNIT UPGRADED TO CLASS 301.

NOTES: CONT (H-1)

LEGEND:

PCAC = PRIMARY CONTAINMENT ATMOSPHERIC CONTROL SYSTEM
RHR = RESIDUAL HEAT REMOVAL
HEPA = HIGH EFF PARTICULATE ABSOLUTE

REF DWGS

| | |
|---|---|
| FLOW DIAGRAM SYMBOLS | FIGURE 1.7-1A |
| FLOW DIAGRAM SYMBOLS | FIGURE 1.7-1B |
| MACHINE LOC REACTOR BLDG | FIGURE 3.8.1-3 |
| RW EQPT & FL DRAINS RB | FIGURE 9.3.3-1C |

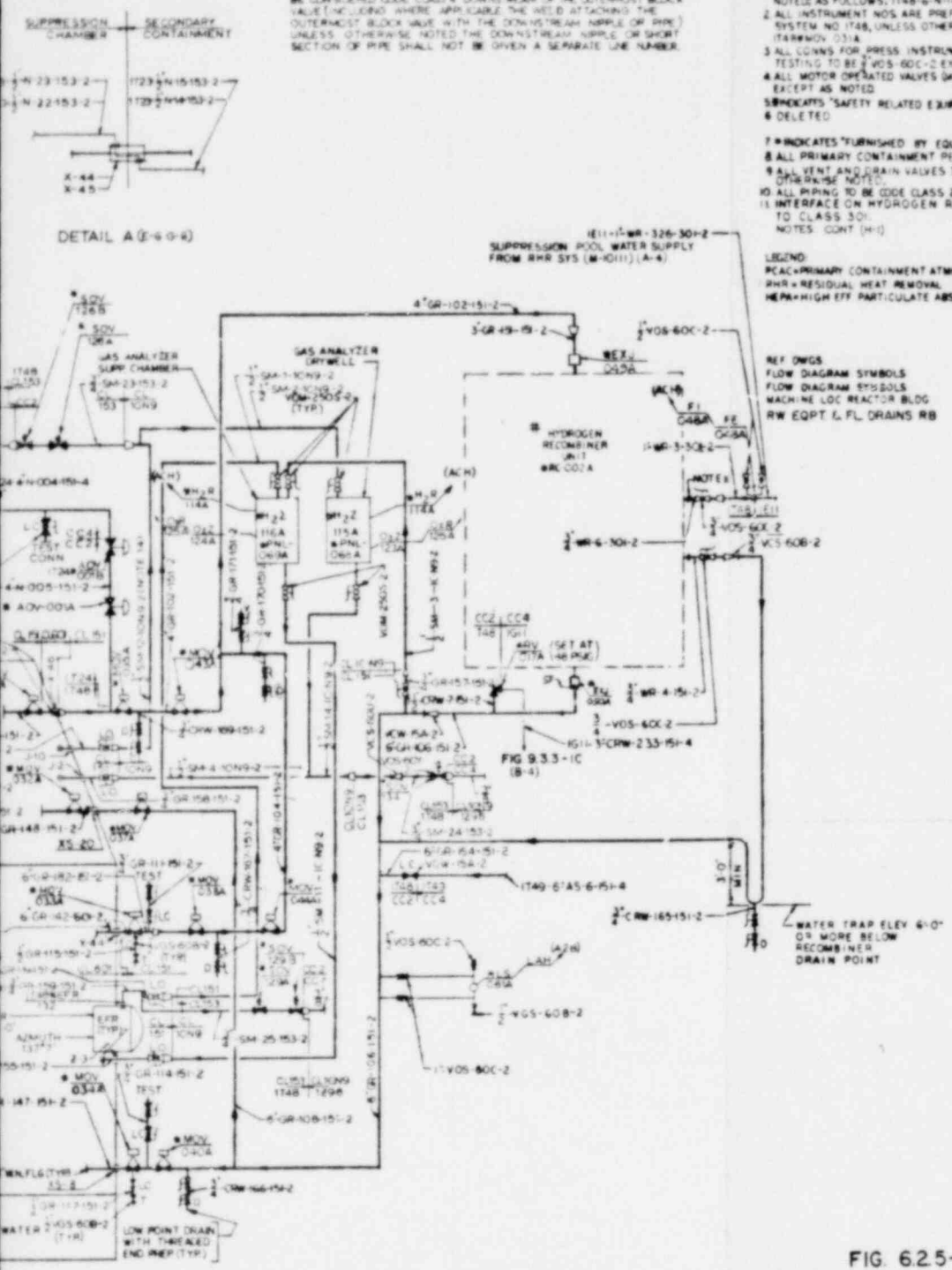



FIG. 6.2.5-1

PRIMARY CONTAINMENT ATMOSPHERIC CONTROL SYSTEM

SHOREHAM NUCLEAR POWER STATION - UNIT 1
FINAL SAFETY ANALYSIS REPORT

## II.K.1.5 SAFETY-RELATED VALVE POSITION

### NRC Position

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

### LILCO Position

A review of safety related valve positions, positioning requirements and positive controls to assure that valves remain positioned in a manner which ensures the proper operation of engineered safety features was performed in response to I&E Bulletin 79-08, Item 6, and sent to the NRC by SNRC-455 dated January 2, 1980. This review identified the four following areas:

1. Motor Operated Valves (MOV) - All Category I MOV's have loss of control power relays which provide input to the following: A. Individually to the computer, B. To one of, or a combination of, system inop alarms, system degraded alarms, or loss of control power alarms. Also, if an MOV has a given safety position and it is moved from that position and loses its ability to return automatically, then its respective system inop alarm is sounded. To further back up the above statements, the NRC requested an audit of remote manual safety related valves via the Electrical SER open item 10 which was done and sent to them by SNRC-296 dated June 9, 1978. Based on the results of the audit, it was concluded and has been confirmed that the existing position indication available is sufficient to ensure safe operation of the plant.

2. Air Assisted Valves - All air assisted valves are designed to fail in their safety position upon loss of air or loss of electrical power.

3. Modulating Valves - In some Category I process systems it was necessary to provide modulating control during a LOCA. These valves use a 120 v AC or 125 v DC Beck actuator instead of instrument air. There are two failure

conditions for these valves: A. Loss of control signal, B. Loss of electrical motive power. On a loss of control signal the valves fail open, close, or as is. On a loss of electrical motive power the valves fail as is. The above failure positions for loss of control signal were determined so as not to cause a loss of system function. If there is a loss of electrical motive power the redundant system provides safety function.

4. Manual Valves - Manual valves are used extensively in Category I systems at Shoreham. Due to their application (test connections, vent and drain lines, instrument root valves, sample connections, and maintenance isolation valves around components such as pumps and heat exchangers), only certain valves have direct remote indication in the main Control Room. However, the operator can determine the positions of the majority of these valves indirectly by use of process instrumentation; e.g., pressure, flow, level, sump levels, etc. In addition, administrative and procedural controls will be used to ensure proper valve position and, in some cases, the valves will be locked in their safety position.

A review of procedures to ensure that safety-related valves are returned to their correct positions following necessary manipulations is being performed together with the procedures review being conducted to verify that the requirements of I&E Bulletin 79-08, Item 8 (NUREG 0737 Item II.K.1.10), are satisfied. The procedure reviews required by NUREG 0737 Items II.K.1.5 and II.K.1.10 and any necessary procedure changes will be completed by September 1981.

## II.K.3.15 Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems

### NRC Position

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

### BWR Owners' Group Discussion

The BWR Owner's Group have reviewed this issue and agree that the current control logic could contribute to an unnecessary degradation of HPCI/RCIC System availability.

### BWR Owners' Group Implementation Criteria

Several design changes are capable of eliminating the unnecessary system isolations that can occur as a result of short term flow peaks in steam supply lines. These changes include the addition of a time delay to the flow sensing isolation logic, the addition of snubber devices to the elbow tap instrument lines, raising the nominal setpoint, or addition of small diameter bypasses around the steam supply valves. The BWR Owners' Group believe the addition of a time delay relay is the best solution because it directly addresses the problem of spurious isolation. Furthermore, this change does not invalidate the design basis safety evaluation of this equipment, thus precluding the need to repeat any safety analyses.

### LILCO Position

LILCO endorses the recommendation of the BWR Owners' Group to adopt a time delay relay scheme to eliminate spurious isolation of the steam supply line isolation valves during the system start sequence. Due to the unavailability of qualified equipment, however, implementation cannot be completed until approximately June, 1982.

## II.K.3.17 Report on Outage of ECC Systems-Licensee Report and Proposed Technical Specification Changes

NRC Position

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

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

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

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

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

LILCO Position

Since Shoreham is not yet operational, LILCO does not have any applicable ECC outage information to contribute to proposing changes which improve the availability of ECC equipment.

## II.K.3.21 Restart of Core Spray and LPCI Systems on Low Level

### NRC Position

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

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

### BWR Owner's Group Discussion

Control of BWR safety systems involves a combination of automatic and manual actions. Although it might appear that additional safety system automation would be purely beneficial, it is the judgment of GE and the Owner's Group that the current low pressure Emergency Core Cooling System (ECCS) logic design represents a balanced solution wherein there is sufficient automation for the short term phase of an incident with the longer term system control being dependent upon the manual actions of the plant operating staff. Any further system automation should be measured against the penalties of increased system complexity, reduced system reliability and restricted operator flexibility.

For a complete discussion of the Owner's Group position, refer to Attachment 1, "BWR Owners' Group Evaluation of NUREG-0737, Item II.K.3.21."

### BWR Owners' Group Implementation Criteria

The current system design is adequate and no design changes are required. This adequacy is based on several factors including the following:

1. Comprehensive nature of BWR operator training
2. Emphasis on reactor water level control during training
3. Emergency Procedure Guidelines
4. Relatively long time available for operator action
5. Extent to which low reactor water level conditions are displayed and alarmed in the control room

Any further automation would unnecessarily increase system complexity, reduce system reliability and restrict operator flexibility.

LILCO Position

LILCO endorses the position of the BWR Owners' Group not to modify the existing logic and controls for Core Spray and Low Pressure Coolant Injection Systems to incorporate an automatic restart capability on loss of water level. For supporting documentation refer to Attachment 1.

Note that the proposed modification to the HPCS system discussed in Attachment 1 is not applicable to Shoreham since only BWR 5 and 6 (not BWR 4) have a HPCS system.

# BWR OWNERS' GROUP EVALUATION OF

# NUREG-0737 ITEM II.K.3.21

## CORE SPRAY AND LOW PRESSURE COOLANT INJECTION SYSTEMS LOW LEVEL INITIATION

## CONTENTS

NUREG-0737 ITEM II.K.3.21

# CORE SPRAY AND LOW PRESSURE COOLANT INJECTION SYSTEMS LEVEL INITIATION

## SUMMARY

The NRC has suggested certain modifications to the BWR Core Spray (CS) and Low Pressure Coolant Injection (LPCI) systems provided as part of the BWR ECCS network. These NRC suggestions center on control system logic modifications that would provide greater automatic system restart capability following manual termination of system operation. General Electric and the BWR Owners' Group have reviewed this issue on a generic basis and do not believe the NRC suggestions are required for plant safety considerations. This conclusion is based on the adequacy of the current ECCS logic design coupled with the potentially negative impact on overall safety of the proposed changes. For the low pressure ECCS these negative impacts include a significant escalation of control system complexity and restricted operator flexibility when dealing with anticipated events. Therefore, we conclude that no modifications be made to the low pressure ECCS with respect to automatic restart.

GE and the BWR Owners' Group have evaluated a modification to the HPCS system which would automate its restart on low level following its trip by the operator. This change would make the HPCS restart logic similar to the HPCI logic which already permits an auto restart on low level. We have concluded that this change, although not required for safety reasons, would lead to a net safety improvement which could be implemented without adverse impact on system performance.

This memorandum provides an overview discussion of GE's BWR ECCS design philosophy and presents the technical rationale for the GE/Owners' Group position on this issue.

## 1. INTRODUCTION

This memorandum has been prepared in response to Item II K.3.21 of NUREG-0737. In this Item, the NRC suggested certain modifications to the Core Spray (CS) and the Low Pressure Coolant Injection (LPCI) Emergency Core Cooling Systems (ECCS) that are provided as part of the BWR ECCS network. The NRC suggestions center on incorporating additional control system logic to provide automatic system restart from a low reactor water level signal following actions by the operators to terminate system operation. The NRC concern is that the reactor operators may terminate ECCS operation when a high reactor water level condition exists but may neglect to reinitiate the systems if a low level condition recurs.

General Electric and the BWR Owners' Group have reviewed the current CS and LPCI system for the plants identified in Appendix C and have concluded that overall BWR safety would not be enhanced by the type of control system modification suggested by the NRC. This memorandum describes the current CS and LPCI logic design and provides the technical rationale for the GE/Owners' Group position. This discussion is generic and includes the LPCI and both the low and high pressure core spray systems (LPCS/HPCS). There are some plant to plant variations in these systems but these variations are not important to the overall technical conclusions presented in this memorandum. Neither the High Pressure Coolant Injection system (HPCI) provided on some pre-BWR/5 reactors nor the Reactor Core Isolation Cooling (RCIC) system is discussed.

Section 2 of the memorandum describes the major elements of the GE ECCS design philosophy that are relevant to any discussion of providing expanded system automatic restart capablity. A full understanding of the significance of CS and LPCI logic changes must be based on a recognition that these systems are part of the interdependent BWR ECCS network; any changes in one system must consider the possible interactive effects amongst the other systems making up the overall ECCS network. This must also include the potential impact on supporting systems such as the standby power supplies and the emergency service water system.

Furthermore, the LPCI system is a sub-system of the Residual Heat Removal (RHR) system which has other safety related functions such as suppression pool (containment) cooling and containment spray. Clearly, these other safety functions must not be compromised by any changes in the LPCI mode of operation.

Section 3.1 describes the sequence of events that would occur during several key reactor system transients. This information is for typical BWR transients and identifies system actions which occur automatically and also what operator actions are required. The intent of these generic event descriptions is to illustrate the adequacy of the current BWR ECCS design and to support the position that no modifications are required on the basis of any safety considerations.

Section 3.2 identifies the points in the transient events where inappropriate operator intervention and errors have the potential for leading to inadequate core cooling. These conditions are reviewed and it is concluded that in no case does the probability for error warrant any ECCS control logic change.

Furthermore, the safety margins incorporated in the BWR design provide considerable time between the point at which the operator should (but does not) take action and the time at which core cooling would be jeopardized. Typical BWR data is provided in Appendix B.

An important point of design philosophy is involved in the discussions presented in this memorandum. Control of BWR safety systems will always involve a combination of automatic and manual actions; the issue raised by this NUREG-0737 Item is simply where and how to define the boundary between these two control methods. The current GE ECCS designs are based on the approach that automatic system initiation is required during the short term phase of any incident but that longer term system control can and should depend upon the manual actions of the plant operating staff. Intuitively, it might appear that additional ECCS automation would be purely beneficial since this would supposedly provide added protection against operator errors and omissions. However, these perceived benefits of extended system automation must be measured against the very real penalties of increased system complexity, reduced system reliability and restricted operator flexibility for dealing with unanticipated events. These considerations are not amenable to precise quantification and control system design decisions must of necessity involve judgements as to relative importance of these competing influences. GE and the BWR Owners' Group believes the current BWR low pressure ECCS logic design has considered all of these factors and represents a balanced solution.

GE and the BWR Owners' believe that the current BWR 5/6 High Pressure Core Spray (HPCS) system is fully adequate and no design changes are required on a basis of any safety considerations. However, there are relatively straightforward HPCS design modifications that would automate the restart of HPCS on low level following its trip by the operator similar to the HPCI logic. This change which would enhance overall plant safety is described in Appendix A of this memorandum.

## 2. GENERAL ELECTRIC ECCS DESIGN PHILOSOPHY

This section provides an overview discussion of the generic GE ECCS design philosophy and design practices as they govern ECCS initiation and operator control of these systems. ECCS control systems must satisfy multiple system design requirements and the information presented in this Section and Section 3 is intended to demonstrate that the current ECCS controls are based on a balanced consideration of these multiple requirements.

## 2.1 LOCA Signals

High drywell pressure* and low reactor water level** are the key accident related parameters that govern operation of the BWR ECC systems. The occurrence of either or both of these signals is taken as an indication that a Loss of Coolant Accident (LOCA) has occurred. This combination provides diversity of initiating signals but it is important to note that the control system hardware does not discriminate between signals generated by the drywell pressure sensors and those produced by the reactor water level instruments. Either or both of these sensed variables can produce a LOCA signal input to the control circuitry.*** The latter does not treat the signals separately and there is currently no way for the control hardware to recognize which parameter is indicating a LOCA condition exists.

This is a significant design feature because it means system logic reset cannot be accomplished until both of these LOCA signals have cleared: and an ECC system cannot be returned to its true standby mode until the logic circuits have been reset. With the current design, automatic restart of any ECC system will occur once it has been placed in the standby condition and an initiation signal recurs. As discussed below, there are in practice many BWR accident sequences where one or both of the ECCS initiation signals will persist for long periods of time. This characteristic complicates any scheme to provide the type of system restart proposed by the NRC.

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* Typically 2 psig.

** Actual setpoints are plant and system dependent. All setpoints are above the top of the active core.

*** Common LOCA logic is developed within each redundant ECCS division, so the core spray and LPCS controls receive the same signal at the same time.

The long term post-LOCA transient is good example of the significance of the combined drywell pressure and reactor water level LOCA signal input to the BWR ECCS. For all but the largest breaks, reflooding of the core will occur relatively soon after the ECCS have been automatically started by the high drywell pressure and/or low reactor water level signals. However, the high drywell pressure condition may persist for extended periods following the accident and the continued presence of this LOCA signal will prevent ECCS logic reset and thus prevent return of these systems to their standby mode. Control system modifications to provide automatic restart on low reactor water level would have to be based on logic that recognizes the possibility of a continuously present drywell pressure signal. The possibility for the drywell pressure signal not being present would also have to be included in the logic; longer term post-LOCA containment pressure conditions are sensitive to factors as break size, break location, type of ECCS equipment operating, etc. and pressures both above and below the 2 psig value could occur depending upon plant conditions.

In summary, the diversity of initiation signals is an important design philosophy that has had a major influence on the current BWR ECCS control system design. However, the BWR LOCA performance is such that one or more ECCS initiation signals can persist for extended periods of time. Any scheme to provide ECCS automatic restart capabilities would have to be complex in order to deal with this possibility. The added safety benefits of an automatic restart design must be balanced against the decreased reliability of the system brought about by the additional control system complexities required to implement the change.

Sections 2.3, 2.6 and 2.7 provide further discussion of this point.

## 2.2 Automatic System Initiation

Immediately following a LOCA that produces either high drywell pressure or low reactor water level, all BWR ECCS will automatically start. Injection of emergency cooling water into the reactor will occur when reactor pressure is within the design range of each particular system. This design feature would not be influenced by any plant modification to provide ECCS automatic restart capability.

Annunciators are set off by the initiating condition and are subsequently acknowledged by the plant operators. The audible alarm is silenced by the operator after he has acknowledged the conditions and determined his required action but the panel light persists until the originating condition disappears. Reoccurrence of the originating condition would cause a new audible alarm and alert the plant operators to the need to reactivate any secured pumps and restore reactor water level. These important control room annunciation/alarm features of the typical BWR together with the BWR reactor water level indicators will provide information that will ensure that the control room staff is continuously aware of the reactor water level condition and will undertake all the necessary safety actions in a timely manner.

## 2.3 Automatic System Termination

The low pressure emergency systems do not stop automatically in the event either the drywell pressure or the reactor water level signals return to non-LOCA conditions. See Paragraph 2.4 for high water level trip of the HPCS system.

In some plants, high-high containment system pressures will cause a portion of the LPCI system to automatically realign to the containment spray or wetwell spray mode of operation. (Some time delay is provided to allow reactor water level recovery). This design feature is intended to enhance the ability of the pressure suppression containment system to accomodate steam bypass of the drywell/wetwell vent system. Reoccurrance of the LPCI autostart signal would create conflicting simultaneous automatic signals which would have to be resolved by a priority logic and its attendant complications.

2.4 System Termination on High Level

In general, flow from the High Pressure Core Spray (HPCS) system is terminated when a high reactor water level condition occurs (typically referred to as Level 8). The intent of this control feature is to prevent 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.

Depending upon the circumstances involved, automatic restart may or may not occur following operator termination of the HPCS system. (See Secion 2.5 for additional discussion ) It should be noted that the Reactor Core Isolation Cooling (RCIC) system is also available for high pressure reactor water makeup duty and can be considered a diverse backup for the HPCS. (See Note 1)

## 2.5 Operator Termination

The reactor operators can, at any time, stop any BWR ECCS system even if a LOCA signal is present. This manual override option is deliberate and is considered by General Electric to be an important safety feature of the BWR ECCS network. This feature provides the plant operators with flexibility for dealing with unforseen but credible conditions requiring a particular system to be shut down. Examples would be equipment difficulties involving gross seal leakage, breaks in ECCS piping, failed ECCS pump motors, load shedding for other post-LOCA operations etc. General Electric strongly believes that any design changes which restrict this operator flexibility would not be beneficial and would not lead to improved plant safety. Because the reactor water level is directly measured in the BWR and the water level is a primary parameter in the operator guidelines, operator action is a highly reliable means of reinitiating low pressure ECCS if needed to assure adequate core cooling. It is believed the overall system reliability is higher if flexibility is included for operator action as compared to a system which cannot be overridden if a LOCA signal is present.

(NOTE 1: The BWR/6 HPCS control logic currently includes a high drywell pressure override of the high level flow termination signal, i.e., if a high drywell pressure signal is present, the HPCS system will not terminate on high level and will flood the reactor and main steamlines. General Electric believes overall plant safety would be improved if this override feature were removed and is currently reviewing such a change with the NRC staff.)

Depending upon the reactor condition, operator termination of a BWR ECCS can be achieved in several ways. Figure 1 is a schematic diagram which illustrates these options for typical low pressure systems. The schematic in Figure 2 illustrates the logic for the BWR/5 HPCS system. The key points to note are:

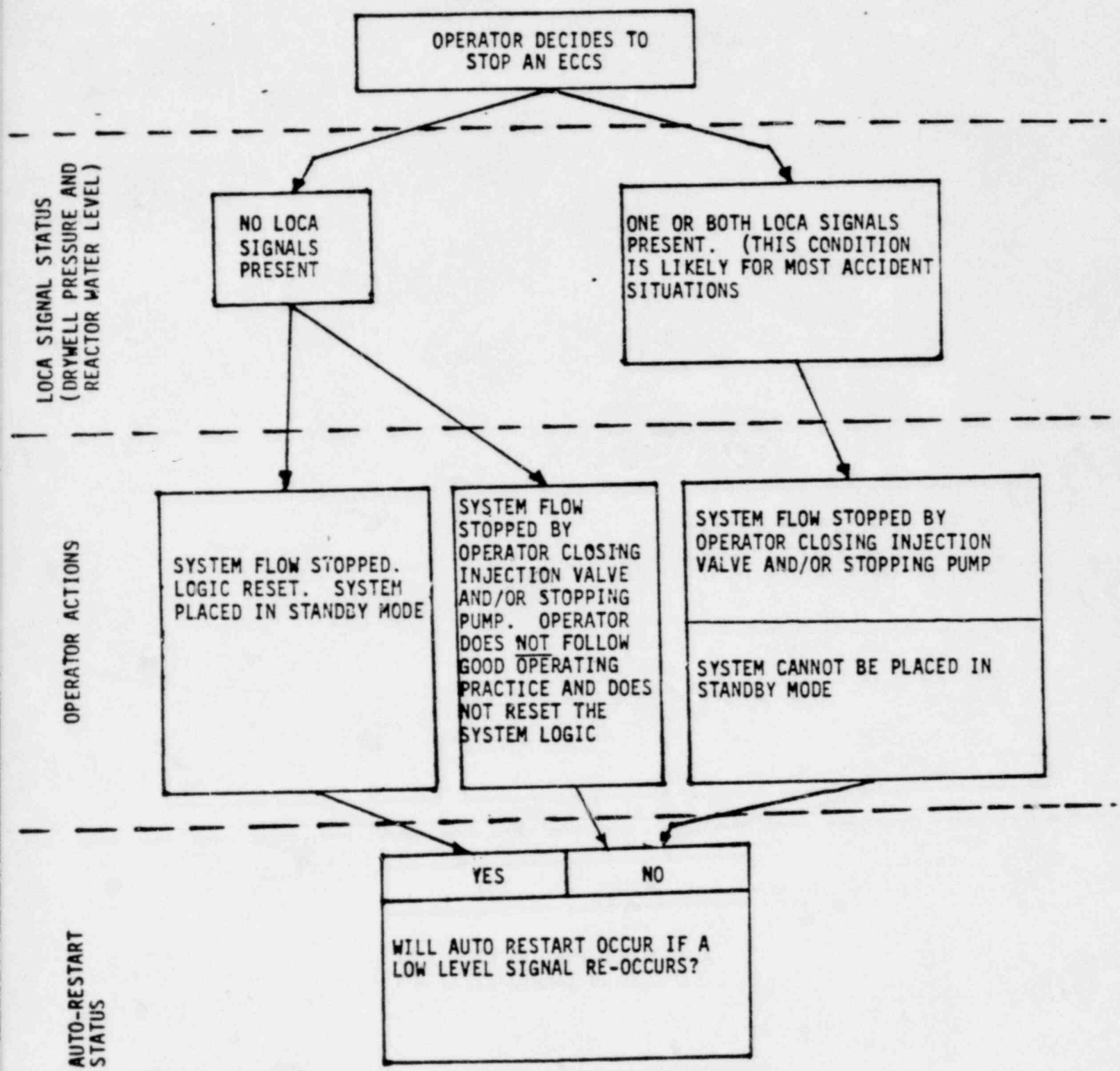
1. If properly secured and returned to the standby mode, all ECCS will automatically reinitiate if a LOCA signal re-occurs. Standby status can be acheived when all previous LOCA signals have cleared and the sytem logic has been reset. Correct operating procedure would be for the operator to attempt to return all ECCS to their standby mode any time a system is being secured; only when conditions such as the continued presence of a LOCA signal prevent this operation would a system be stopped and left in a non-standby mode.

2. If a LOCA signal persists, system flow can be terminated but the system cannot be returned to standby status. A typical ECCS system logic permits the operator to override the incoming automatic start logic (from the persistent LOCA signal) by use of either the "stop" position of the pump manual switch or the "close" position of the system injection valve. Momentary contact of either switch actuates logic elements which block the incoming automatic initiation signal. Once blocked, the automatic signal no longer controls pump or valve action and any subsequent system operation will be dependent upon manual operator actions.

3. An improperly secured system (eg: an injection valve closed but system not returned to standby mode) will not automatically restart if a LOCA signal reoccurs.

OPERATOR TERMINATION OF BWR
EMERGENCY CORE COOLING SYSTEMS:

A SCHEMATIC SHOWING TYPICAL OPTIONS




*OPERATOR RESPONDING TO EITHER A MALFUNCTIONING SYSTEM OR A NEED TO INITIATE OTHER SAFETY RELATED FUNCTIONS (EG: ESTABLISH SUPPRESSION POOL COOLING)

FIGURE 1

OPERATOR TERMINATION OF BWR ECCS

A SCHEMATIC SHOWING BWR/5 HPCS TERMINATION ON HIGH REACTOR WATER LEVEL

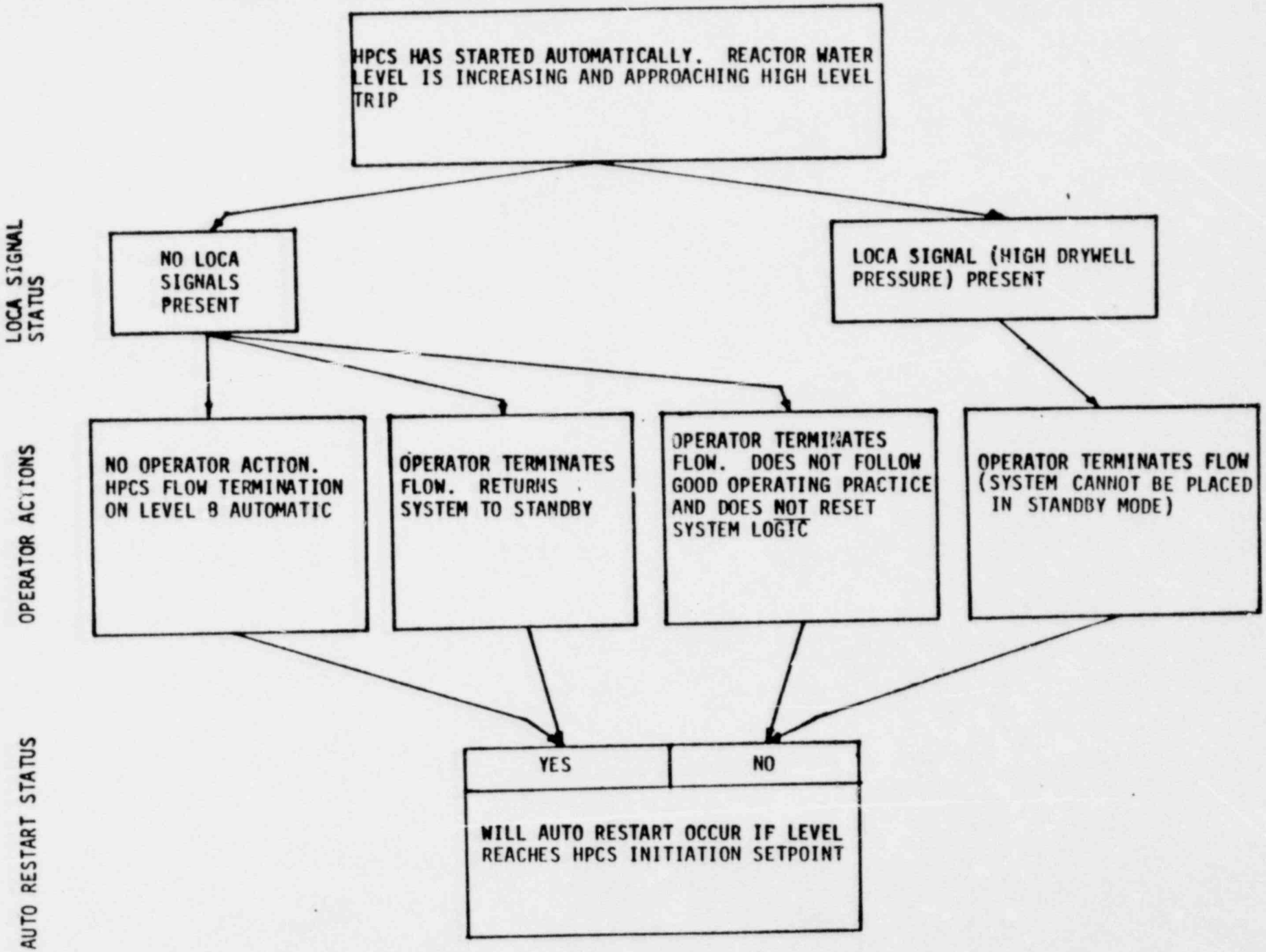



FIGURE 2

## 2.6 Long Term Control

BWR emergency system design is based on the assumption that long term control of the reactor will be completely dependent upon operator actions. This long standing design philosophy has been consistently applied to reactor control following both non-LOCA transient events (such as turbine trip) and also to the complete spectrum of credible loss of coolant accidents. A good example of this philosophy is the complete manual control of the multiple operations required to establish the long term post-LOCA containment cooling functions. Post-LOCA containment cooling is a key safety function since it prevents containment overpressurization and is thus required to support long term cooling of the core.

Providing purely manual control of the long term BWR transients is based on the thesis that the operator will ensure continued core cooling. This manual approach is considered superior to providing the very complex equipment and controls that would be necessary for comprehensive automatic ECCS restart capabilities during these transients.

As an indication of the potential complexity of the control systems that would be required, the following are some of the major long-term transient considerations that would have to be accounted for.

1. In many cases, the station standby power sources do not have sufficient capacity to permit all emergency systems to run simultaneously. The plant operators must establish priorities and make the necessary power assignment decisions. An example of this process would be the decision to shut down one or more of the multiple ECCS in order to provide power to the emergency service water pumps. This is clearly an appropriate action for the operators to take since the multiple ECCS will be providing redundant core cooling and the essential service water system must be activated if the containment cooling and pressure control functions are to be established.

Any scheme to automatically restart the ECCS in a vessel injection mode would have to recognize and account for these other essential post-LOCA activities as well as recognize unavailable or failed systems and equipment.

2. For many plants, operator action is required to ensure adequate ECCS pump Net Positive Suction Head (NPSH) during events involving elevated suppression pool temperatures. In most cases, automatic ECCS system initiation does not involve any system flow control. Consequently the system will operate at the maximum flow rate as vessel pressure reaches drywell pressure. This operating mode is usually referred to as the run out condition and it involves the most severe NPSH requirement at the pump suction. NPSH conditions can (in some cases) lead to pump cavitation as the suppression pool water temperature increases. These undesirable NPSH situations are avoided by the plant operator manually adjusting the system flow rate to design values. Again, this aspect of design would have to be accounted for in any scheme to provide auto-reinitiation capability.

3. Many BWR transient and accident events involve significant release of reactor system energy to the suppression pool which increases the pool temperature and containment pressure. Control of these temperature/pressure conditions is achieved by manually placing the LPCI/RHR system in the suppression pool cooling mode. This LPCI/RHR mode, in conjunction with emergency service water system operation, permits rejection of the excess suppression pool energy to the station ultimate heat sink. Much of the equipment used for this cooling function is also used for the LPCI ECCS mode of the RHR system. Any scheme to provide automatic initiation of the ECCS system would either have to bypass the LPCI system after it has been assigned to the suppression pool cooling function or automatically realign the equipment to the LPCI mode.

Consideration of the second option provides a good example of the many practical difficulties associated with rectroactive modification of BWR ECCS systems. Automatic realignment of the RHR system from the suppression pool cooling mode to the LPCI mode would have to recognize the "as-built" characteristics of the hardware involved. For example, the typical RHR pool return line valve is a 12 - 18 inch valve which would require 90 seconds to close whereas the LPCI injection line is a 12 - 24 inch valve which would open in 24 seconds. This represents a 3:1 valve closure period mis-match and any simultaneous signal to realign the RHR system would result in a significant period of time during which the RHR pump would be supplying flow to both flow paths. The RHR pumps are not designed for the excess duty associated with this mode of operation: inadequate pump NPSH, pump motor overloading and auxiliary power source overloading are potential problems that would have to be addressed. Clearly, these types of hardware problems are not insurmountable but would have to be addressed as part of any rectroactive ECCS modifiction program.* The intent of this discussion of potential difficulties is not to suggest that rectroactive ECCS system logic changes are impossible but rather to highlight the non-trival hardware changes that may accompany any control system logic redefinitions.

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* Additional logic to avoid the valve timing mismatch requires additional LPCI valve permissives and so adds to the probability of failure.

## 2.7 BWR Geometry Considerations That Impact System Logic

The BWR core and internals configuration are such that certain design basis break locations and sizes do not permit complete post-LOCA reflooding of the core. For jet pump plants, very large ruptures in the external recirculation system pipe allow the ECCS to reflood the reactor vessel only to the elevation of the jet pump suction plane. This elevation is at approximately 2/3 of the core height. However, the actual water level inside the shroud is considerably higher due to the existence of voids. For non-jet pump plants large recirculation line breaks do not permit full reflooding of the core. Adequate core cooling is achieved under these conditions for either reactor type but the reactor water level can never be restored to the ECCS initiation level.

This characteristic complicates any scheme to provide automatic reinitiation of the ECC systems on low water level. For large breaks in jet pump plants, inadequate core cooling would probably have to be defined so as to be based on the 2/3 core height level. This revised definition would have to be in addition to the current initiation level which is conservatively identified as a water elevation <u>above</u> the core. It is not clear what comparable alternative signal could be used in the case in the non-jet pump plants. However, it is believed that the minimal need for (and benefits of) providing automatic ECCS reinitiation for large BWR recirculation line breaks does not justify the penalties associated with the significantly more complicated control system that would be required. In summary, the current ECCS logic is well suited to the BWR geometry characterisitcs and no changes are required on the basis of the inadequacies in the current design.

## 3. TYPICAL EVENTS INVOLVING ECCS INITIATION

### 3.1 Event Description

Typically analyzed BWR LOCA and non-LOCA events are discussed in this Section of the memorandum; the events have been treated generically. In each case the emphasis is based on interactions between the LOCA signal and the actions the plant operator can or must take to ensure safe plant conditions. The event descriptions are based on current ECCS control system logic.

The following events have been selected as representative BWR transients:

1. A design basis recirculation line break which will not permit reflooding of the core above the 2/3 core elevation. This accident is included as a base case to illustrate the reasons for the existing system logic.

2. A small break not involving significant loss of reactor water inventory. This accident will lead to high drywell pressure but not a low reactor water level ECCS initiation signal.

3. An intermediate size loss of coolant accident that involves some core uncovery but with a subsequent reflooding of the reactor by the ECCS.

4. An upset transient that produces a momentary reactor water reduction and thus HPCS initiation on low water level but no high drywell pressure LOCA signal.

Tables 1 through 4 show the major sequence of events for these four transients.

## TABLE 1

### TYPICAL BWR TRANSIENTS

### CASE 1: DESIGN BASIS RECIRCULATION LINE BREAK

#### SEQUENCE OF EVENTS

- Break occurs
- High drywell pressure signal
- Low reactor water level signal

These signals will persist indefinitely and cannot be reset.

- All ECCS start and inject water into the vessel automatically
- Core heat-up terminated, all ECCS running, core flooded to 2/3 height. In some cases, part of the LPCI flow may automatically be diverted to containment or wetwell spray.

#### END OF SHORT TERM BLOWDOWN PHASE OF ACCIDENT

Core cooling dependent upon operator actions

- Multiple operator actions to establish long term post-LOCA core and containment cooling. Actions include some ECCS termination, standby power reassignments, emergency service water startup, actuation of suppression pool cooling, pump throttling to assure adequate NPSH, elimination of unnecessary ECCS pump operation so as to minimize pump heat input to the suppression pool etc.

## TABLE 2

### TYPICAL BWR TRANSIENTS

### CASE 2: SMALL BREAK NOT INVOLVING SIGNIFICANT LOSS OF REACTOR INVENTORY (BWR 5/6)

#### SEQUENCE OF EVENTS

- Break occurs
- High drywell pressure signal - signal will persist indefinitely
- No low reactor water level
- All ECCS start automatically (low pressure systems will not inject because of high reactor pressure)
- HPCS Injection

OPTION 1

- HPCS flow terminates automatically on high level (Level 8) (assuming deletion of high drywell pressure inhibit for BWR/6)
- HPCS auto restarts on initial level (Level 2)
- Continuous automatic reactor water level control

OPTION 2

- Operator observes increasing reactor water level and terminates HPCS by stopping pump or closing injection valve. This action precludes subsequent automatic initiation on low level
- Subsequent HPCS restart requires operator action. Because of persistent high drywell pressure, system logic cannot be reset and system returned to standby

#### END OF SHORT TERM PHASE OF EVENT

Core cooling dependent upon operator actions

- Multiple operator actions to inititate orderly shutdown of reactor. Depending upon equipment availability, heat rejection will be to main condenser, suppression pool, or normal shutdown path. Considerations will be to establish core and containment cooling, assure adequate power supply distribution, start emergency service water pumps, throttle pumps to assure adequate NPSH, etc.

## TABLE 3

## TYPICAL BWR TRANSIENTS

## CASE 3: INTERMEDIATE LOSS OF COOLANT ACCIDENT

### SEQUENCE OF EVENTS

- Break occurs
- High drywell pressure signal. (This signal will persist indefinitely)
- Low reactor water level signal. (Level will be recovered at some point in the accident)
- All ECC systems start automatically
- Core uncovery/heatup transient terminated. All ECCS running, reactor vessel flooded. In some cases, part of the LPCI flow may be automatically diverted to containment spray.

### END OF SHORT TERM PHASE OF ACCIDENT

Core cooling dependent upon operator actions

- Multiple operator actions essentially same as those identified in Table 1 for the Design Basis Accident (DBA)

## TABLE 4

## TYPICAL BWR TRANSIENTS

## CASE 4: UPSET TRANSIENT (BWR 5/6)

### SEQUENCE OF EVENTS

- Upset event
- Low reactor water level signal occurs (either due to loss of feedwater or because of momentary level reduction due to void collapse). High drywell pressure does not occur.
- High pressure system starts and injects
- Reactor water level increasing

OPTION 1 | OPTION 2

| OPTION 1 | OPTION 2 |
|---|---|
| - HPCS flow terminates automatically on high level | - HPCS flow terminated by operator. Logic cleared, system returned to standby mode |
| - HPCS auto restarts when initiation level reached | - HPCS auto restart if initiation level reached |
| - Continuous automatic reactor level control | - Repeat of cycle. Continuous automatic reactor level control |

### END OF SHORT TERM PHASE OF EVENT

- Multiple operator actions essentially the same as those identified in Table 2

## 3.2 Assessment

The thrust of the NRC position as stated in the NUREG-0737 Item can be summarized as follows:

> Is it possible that the plant operators could stop an ECC system at a time and in a manner that would, unless the system is manually restarted, lead to inadequate core cooling? If this is the case, and since there is a remote chance the operator may not restart the system, restart should be made automatic.

The simple response to this position is that the current BWR ECCS design does indeed permit the plant operators to terminate system operation in a way that would eventually jeopardize cooling of the core assuming the operator ignors the water level instrumentation and procedures. However, a review of the particular circumstances that would have to be involved leads to the conclusion that this is not necessarily an unacceptable situation which must be immediately remedied by providing additional ECCS automation. To support this position, the typical generic events described in Table 1 through 4 have been subjected to the following questions.

- What operator actions are required?
- What deleterious operator actions are possible?
- Could the deleterious operator actions lead to degraded core cooling?
- Is an ECCS logic design change required to protect against the possible operator errors?

Table 5 summarizes the response to these questions for the four typical generic BWR transients described in Section 3.1.

A review of Table 5 shows that the current ECCS control logic coupled with reasonabale operator actions provides adequate core cooling throughout the four typical events presented. However, there are three general circumstances where it is possible (but not probable) for operator errors to produce conditions that could potentially lead to degraded core cooling. These conditions are:

1. Deliberate operator termination of multiple ECCS during the earlier phases of an incident when the sytems have been automatically initiated. In general, automatic restart will not occur because the initiating signals (high drywell pressure and low water level) will still be present and will preclude the system logic reset. 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 jeopardize the core cooling process. In actual practice, one of their highest priority activities will be to assess the situation to assure all emergency systems have started correctly and attempt to start any that may not have. The alternative to providing this operator flexibility would be to design the system so that any termination attempt by the operators would be overridden. This is not considered good design practice since it provides no flexibility for the operator to deal with unanticipated situations in which overall plant safety may be increased if a malfunctioning ECCS system can be shut down. An example of the latter would be to secure a system that has gross seal leakage that could potentially flood an ECCS compartment and deplete pool water.

2. A second general circumstance during which errors and omissions could potentially lead to degraded core cooling conditions would be a failure of the operators to adequately consider core cooling requirements during the long term period. During this longer term phase, the plant operators are manually setting up the auxiliary systems to support eventual termination of the incident. In the event of degraded core cooling, automatic ECCS initiation is unlikely to occur because the systems will not be in a true standby mode. Consequently, adequate core cooling is dependent upon correct operator actions.

**IMAGE EVALUATION**
**TEST TARGET (MT-3)**

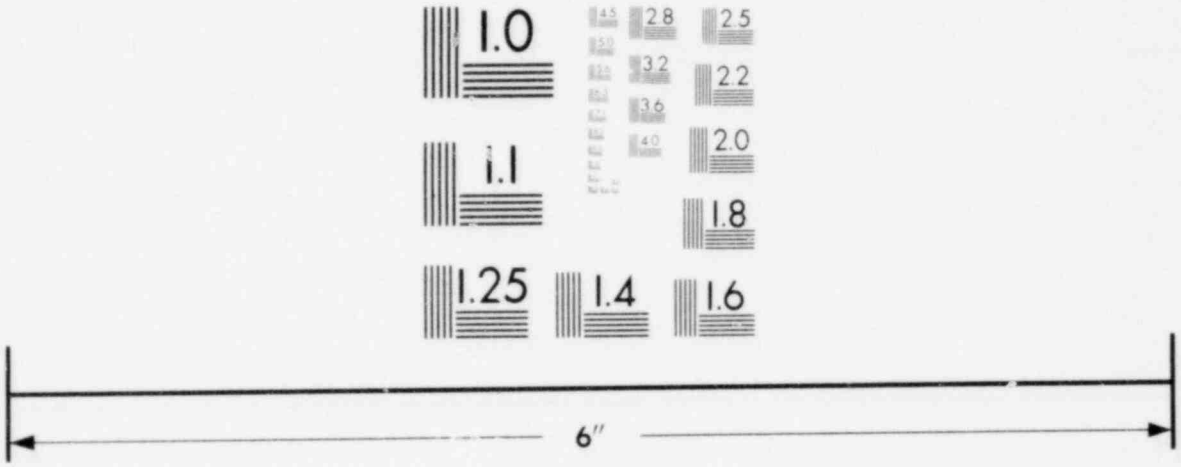
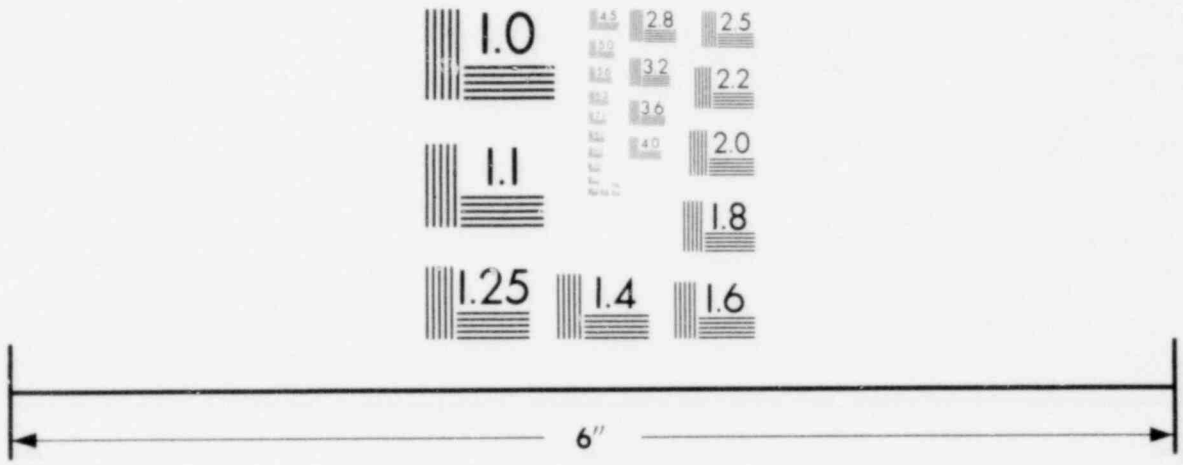


**IMAGE EVALUATION**
**TEST TARGET (MT-3)**



Again, this aspect of ECCS design is considered fully acceptable because of the time available between attaining level one and the occurrence of high fuel clad temperatures. (See Appendix B) The operator must take manual control of all systems during this period and it is not considered credible that he would provide inadequate cooling to the core. As discussed in Table 5, the alternative would be to provide the complex logic necessary to automaticaly restart certain ECCS. This would involve a major escalation of control system logic complexity and the benefits of added protection against unlikely operator error do not appear to compare favorably with the penalties of increased control system complexity, decreased system reliability and the loss of operator flexibility in dealing with unanticipated events.

3. During upset transients and small breaks, the highest reactor operator priority with respect to control of water level will be to avoid overfilling the vessel and flooding the main steam lines. These events will initiate the HPCS and the control logic is capable of automatically maintaining the reactor water level within the HPCS level control range (i.e. between the high level trip elevation and the low level system initiation setpoint). However, it is highly desirable for the plant operators to intervene in this automatic process and assume manual reactor water level control. The key incentive is to prevent the water level from reaching Level 8 since in addition to the HPCS, both the feedwater system (if operating) and the RCIC will be tripped on high level. Consequently, it is probable that for the types of events described in Tables 2 and 4, the plant operators will intervene fairly early and assume manual HPCS control. Under normal circumstances, good operating practice will result in the system being returned to a standby condition anytime system operation is terminated. Automatic restart on low reactor water level will then occur.

If a persistent LOCA signal is present, it will not be possible to return the HPCS to a standby mode and continuous manual control will be required. 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. However, the availability of level data coupled with operator training that has stressed the central importance of adequate water level will ensure appropriate and timely operator control of the HPCS during transients and small break accidents.

This conclusion is further reinforced when it is remembered that during a transient event, at least one half hour of zero reactor makeup flow conditions can be permitted to exist before clad temperatures approaching 2200 F will occur. (See Appendix B)

NOTE: The High Pressure Core Spray (HPCS) system currently restarts automatically if the Level 2 initiation signal reoccurs and the system is in the fully automatic mode or the system had previously been returned to standby conditions. Our evaluation of Item II.K.3.21 has considered the potential benefits of modifying the HPCS logic to extend automatic restart on Level 2 following manual termination. (See 2.4 and 2.5) This logic is already included in the HPCI system design. It has been concluded that such HPCS changes are not required by plant safety considerations. However, the changes that would provide this capability appear to be relatively straightforward and may provide additional safety margin. The recommended changes are described in Appendix A.

TABLE 5

| EVENT | CONDITION | REQUIRED OPERATOR ACTIONS | POSSIBLE DELETERIOUS OPERATORS ACTIONS (A) | COULD (A) LEAD TO DEGRADED CORE COOLING | IS A DESIGN CHANGE REQUIRED TO PROTECT AGAINST (A) | COMMENTS |
|---|---|---|---|---|---|---|
| 1, DBA | Short term blowdown phase of accident | None | Operator could conceivably intervene and terminate flow. Systems would not automatically restart. (Logic cannot be cleared because initation signals are present) | Yes, if sufficient systems were stopped | No. Water level maintenance is emphasized during operator training and reinforced by the Emergency Procedure Guidelines | Operator would have multiple indications that a loss of coolant accident had occurred. It is not credible that he would stop sufficient ECCS to cause degraded core cooling. Preventing manual override is not good design practice. See Section 2.5 |
| 1, DBA | Long term post-LOCA core and containment cooling | Multiple actions required. See Table 1 | Core cooling could be interrupted by operator actions which violate guidelines and procedures. Automatic system restart would not occur because high drywell and low water level signals are continuously present and preclude logic reset | Yes, if sufficient systems are stopped | No. It is reasonable to assume the operator will follow procedures and accomplish all long term core and containment cooling functions satisfactorily. Extended time periods are available. Water level does not recover above 2/3 core height; however up to 20 minutes is available before zero ECCS flow would cause excessive fuel heat-up. See Appendix B | Redesign of the ECCS control logic to provide automatic restart of the certain ECCS would require a major complication of control system logic. This expanded logic would have to recognize and account for the multiple considerations identified in Table 1 and Section 2.6. (The pool cooling function, limited stand-by power sources, pump NPSH, service water requirements etc). The benefits of added protection against operator error do not balance the penalities of increased control system complexity (and thus failure rate) and loss of operator flexibility in dealing with unanticipated events |
| 2, Small Break | HPCS has started automatically and is injecting into the reactor vessel | None, other then to monitor the situation especially reactor water level. System will automatically terminate flow on high level and restart at low level initiation value | Premature termination of HPCS flow. System cannot be returned to standby mode because LOCA signal present and will not permit logic reset | No, remainder of ECCS network would automatically provide cooling. It is probable the operator would manually re-initiate HPCS flow. RCIC is a backup | No. Low water level is annunicated and alarmed in the control room; there is a considerable period of time before zero makeup flow would cause fuel heat-up; operator training and the Emergency Procedure Guidelines emphasize level control | Probability of operator terminating HPCS flow and allowing the vessel level to reach the ADS setpoint in very low. Even if this occurs, core cooling is never jeopardized |
| 2, Small Break | Same as above | Same as above | As above but further compounded by operator securing the low pressure systems. None of the systems can be returned to the full standby mode and would not restart automatically | Yes, but not considered a credible situation. Operator would continue operator water level with HPCS and RCIC | No. (See above) | Probability of this series of multiple operator errors is less than above |

TABLE 5

| EVENT | CONDITION | REQUIRED OPERATOR ACTIONS | POSSIBLE DELETERIOUS OPERATORS ACTIONS (A) | COULD (A) LEAD TO DEGRADED CORE COOLING | IS A DESIGN CHANGE REQUIRED TO PROTECT AGAINST (A) | COMMNETS |
|---|---|---|---|---|---|---|
| Small Break | Long term actions to initiate orderly shut-down to cold conditions | Multiple actions required. See Table 2 | Core cooling could be interrupted by operator actions which violate guidelines and procedures. Automatic system restart would not occur because the continuously present high drywell pressure prevents logic reset | Yes, if sufficient operator error are made | No. It is reasonable to assume the operator will follow procedures and accomplish all long term core and containment cooling functions satisfactorily. Extended time periods are available. (See Appendix B) | See comments on Event 1, BDA, long term post-LOCA transient |
| Inter-mediate Break | Short term blowdown phase of the accident | Same discussion and conclusions as for the DBA. No design changes required. | | | | |
| Inter-mediate Break | Long term post accident core and contain-ment cooling | | | | | |
| Upset Transient | Short term responses. Reactor water level rising | None other than to monitor the situation es-pecially water level. HPCS is capable of auto-matic stopping and starting within its level control range | HPCS system flow termin-ated and system returned to standby mode. (Re-quires no initiation signal present | No, system will automati-cally restart on low level | No | If the plant operator takes no action or if he correctly terminates HPCS flow, the system will respond automatically to low reactor water signal |
| Upset Transient | Short term response. Reactor water level rising | As above | HPCS system flow termin-ated by simple pump stoppage or injection valve closure. System not re-turned to standby mode | Adequate core cooling will eventually require operator action. HPCS will not auto restart and ADS initiation will require manual action | No. An unlikely operator error is involved. Also, RCIC system would be available as a backup. See comment on Item 2. Extended time periods available. See Appendix B | |
| Upset Transient | Long term post incident recovery | Same comments and conclusions as other long term transients i.e. adequate core cooling dependent upon operator action. Situation acceptable | | | | |

## 4. CONCLUSIONS

The current BWR ECCS control logic as well as the CS and LPCI logic modifications suggested by the NRC in NUREG-0737 Item II.K.3.21 have been reviewed. This review has included a consideration of all aspects of HPCS, LPCS and LPCI system operation which would be influenced by any expanded automatic restart capability. It is concluded that the current system design is adequate and no design changes are required. This conclusion is based on a combination of factors that include: the comprehensive nature of BWR operator training, the emphasis placed in this training on reactor water level control, the Emergency Procedure Guidelines, the relatively long time the operator has to correct errors and the extent to which low reactor water level conditions are displayed and alarmed in the control room. The most important consideration is that the benefits of providing enhanced automatic ECCS reinitiation do not justify the associated penalties of increased system complexity, reduced system reliability, restricted operator flexibility and the other undesirable effects discussed in this memorandum.

In summary, General Electric and the BWR Owners' Group believe the current BWR low pressure ECCS design, when coupled with rigorous and continuous operating staff training programs, represents the optimum approach to BWR safety. No modification of existing LPCI and low pressure core spray system need to be undertaken. Modification of the HPCS system to automate restart on low level following manual trip, although not required for safety considerations, will lead to a net improvement in overall ECCS performance.

## APPENDIX A

High Pressure Core Spray (HPCS) System Modifications

GE and the BWR Owners' Group have reviewed the current HPCS system and have concluded that no system design changes are required. However, some additional safety margin may be added to the BWR design by making a relatively straightforward modification to the HPCS control logic to provide automatic restart of the system following manual termination of pump operation. The purpose of this Appendix is to conceptually describe this potential HPCS design change.

Summary

Auto restart of HPCS after manual stop can be provided if a logic system can be developed which:

(1) Restarts the HPCS pump on Level 2,
(2) Blocks high drywell pressure restart,
(3) Self clears if both auto signals disappear, and
(4) Still allows injection valve closure or pump stop if absolutely essential for protection of the public.

Any such design should adhere to the applicable portions of IEEE 279-1971.

Existing Logic Design

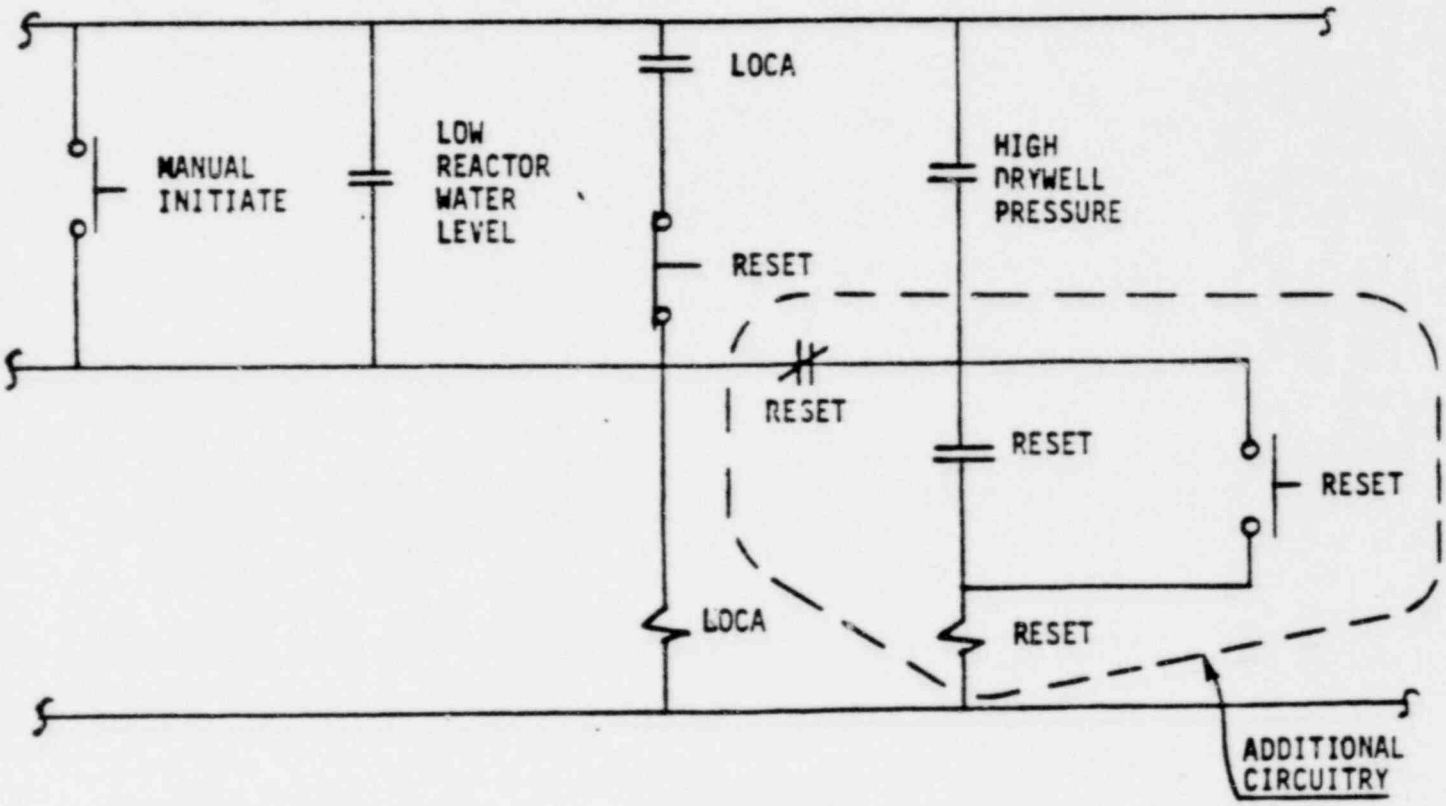
The HPCS system is initiated by either high drywell pressure or low (Level 2) reactor water level. Each parameter has four sensors and analogic trip units or four switches set up in a one-out-of-two-twice logic scheme. The above logic is assembled and the output fed to an OR gate along with the system level manual initiation signal. The output of the OR gate is a LOCA initiation signal which is sealed in. A reset switch permits release of the seal in. The assembled initiation signals are not sealed in so that they self-clear when the abnormal condition disappears.

Proposed Modification

The feature being considered will reset the auto initiation signal, on level and block the continuing auto initiation signal based on high drywell pressure. This will allow auto HPCS restart on low level after operator stop of the pump. It does block auto restart on high drywell pressure unless drywell pressure decreases below the setpoint and again increases above the setpoint. A decrease in drywell pressure below trip level will remove all reset features and return HPCS logic to the original status. The HPCS pump is not stopped automatically by any reset. Pump stop still requires operator action.

System isolation must still be possible with or without this modifiction.

HPCS INITIATE CIRCUITS




CONCEPTUAL DESIGN
HPCS INITIATION CIRCUIT
USING RELAY LOGIC
(SOLID STATE LOGIC IS EQUALLY ADAPTABLE)

## APPENDIX B

As discussed in the body of this memorandum, General Electric and the Owners' Group believe the current ECCS control logic is fully adequate. This position is based on a combination of factors one of which is the period of time available between the time at which the operator should (but does not) start an idle ECCS system and the time at which inadequate core cooling may begin. As discussed below this can be a fairly long time period and the purpose of this Appendix is to demonstrate this safety margin that is built into the BWR.

Assuming that after operator termination of a system, there is no source of reactor water level makeup at all and further assuming the core is initially at saturation temperature conditions, the following table summarizes the time between pump flow termination and the occurrence of 2200°F fuel clad temperatures.

| Case | Time to Reach 2200°F |
|---|---|
| 1. Isolated - no break | |
| Boil off from Level I (Typically only a few feet above the top of the core) | 30 minutes |
| 2. Isolated - large recirculation system break | |
| Boil off from top of jet pump | 15 to 20 minutes |

In Case 1, the reactor water level is initially at the ECCS initiation value (Level I). It is assumed that there is no ECCS flow and the reactor boil-off process results in decreasing reactor water level leading eventually to core uncovery. This case is representative of transients involving no reactor system break. It should be noted that Level 1 is a very low reactor level (one or two feet above the top of the active core) and the allowable period of zero reactor water make up is considerably extended if it is assumed to start with a higher reactor water level condition.

Case 2 is representative of a large recirculation line break in a jet pump plant. For this case, it was assumed that there was no water outside the shroud and that the collapsed water level inside the shroud is at the top of the jet pump. The swollen water level is actually somewhat higher.

The heat up times given in this Appendix are minimum estimates of typical BWR values. Times would be longer if the events started with less than maximum expected core decay power and/or if the ECCS flow is terminated later in the transient. Availability of other makeup systems such as the control rod drive flow could significantly extend the time before core heat up would occur.

The above information clearly demonstrates that there is a significant period of time available for the operator to recognize that he has inadvertently permitted the reactor water level to decrease and for him to take the necessary corrective action.

## APPENDIX C

### Participating Utilities

### NUREG-0737 II.K.3.21

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

| | |
|---|---|
| Boston Edison | Pilgrim 1 |
| Carolina Power & Light | Brunswick 1 & 2 |
| Commonwealth Edison | LaSalle 1 & 2, Dresden 1-3<br>Quad Cities 1,2 |
| Georgia Power | Hatch 1 & 2 |
| Iowa Electric Light & Power | Duane Arnold |
| Niagara Mohawk Power | Nine Mile Point 1 & 2 |
| Nebraska Public Power District | Cooper |
| Northeast Utilities | Millstone 1 |
| Northern States Power | Monticello |
| Pacific Gas & Electric | Humboldt Bay 3 |
| Philadelphia Electric | Peach Bottom 2 & 3; Limerick 1 & 2 |
| Power Authority of the State of New York | Fitzpatrick |
| Tennessee Valley Authority | Browns Ferry 1-3, Hartsville 1-4,<br>Phipps Bend 1 & 2 |
| Detroit Edison | Enrico Fermi 2 |
| Long Island Lighting | Shoreham |
| Mississippi Power & Light | Grand Gulf 1 & 2 |
| Pennsylvania Power & Light | Susquehanna 1 & 2 |
| Washington Public Power Supply System | Hanford 2 |
| Cleveland Electric Illuminating | Perry 1 & 2 |
| Houston Lighting & Power | Allens Creek |
| Illinois Power | Clinton Station 1 & 2 |
| Public Service of Oklahoma | Black Fox 1 & 2 |
| Vermont Yankee Nuclear Power | Vermont Yankee |

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

NRC Position

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

LILCO Position

The RCIC system is available for mitigation of all transients where the loss of HPCI is assumed. The initial actuation of RCIC is automatic and it is a Seismic Category I system with a water source from the condensate storage tank. The water supply for the RCIC system is assured since the lower section (10 feet) of the condensate storage tank, including the connection to the 16-inch suction piping is Seismic Category I to insure a 100,000 gallon supply of water to the HPCI and RCIC systems.

The water available in just the lower 10 feet of the condensate storage tank is sufficient to supply RCIC for several hours, thus providing more than adequate time for switchover of the RCIC suction using the remote manual valves available for this purpose at the appropriate time. This switchover has been incorporated into the Station Operating Procedures.

Therefore, due to the availability of the RCIC water supply for several hours after a seismic event, automatic switchover to the suppression pool is not required.

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

### NRC Position

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

### BWR Owners' Group Discussion

Level instrumentation, calibration, location, and scale ranges are based on the intended utilization and function of the associated instruments. A common water level reference presently exists for all normal operating and accident conditions except the large break LOCA. This common water level reference is located near the bottom of the steam drier, which is a functionally appropriate point for ensuring proper steam quality during normal operation. The water level reference for a large break LOCA is near the top of the active fuel, which is also functionally appropriate since the operator's main concern is to keep the core covered.

For a complete discussion of the Owners' Group position, refer to Attachment 1, "BWR Owners' Group Evaluation of NUREG-0737 II.K.3.27."

### BWR Owners' Group Implementation Criteria

The current BWR water level indication system is fully adequate to allow plant operators to respond properly under all postulated reactor conditions. No design changes are, therefore, required.

### LILCO Position

LILCO endorses the position of the BWR Owners' Group that no design changes are required to the current water level indication system. For supporting documentation, refer to Attachment 1.

Note on Table 1 of Attachment 1, for Shoreham Level 2 isolates the MSIV's, not Level 1 as indicated.

ATTACHMENT 1

# BWR OWNERS' GROUP EVALUATION OF

# NUREG-0737 II.K.3.27

# COMMON WATER LEVEL REFERENCE

# TABLE OF CONTENTS

SUMMARY

NUREG-0737, Item II.K.3.27, "Common Water Level Reference", requires that all reactor pressure vessel water level indicator scales be based on a common reference zero. The intent is to reduce a perceived potential for operator confusion due to the different reference points of the various reactor vessel water level instruments.

General Electric and the BWR Owners' Group have reviewed the reactor water level instruments currently provided in a typical BWR control room, and have concluded that this instrumentation provides the plant operators with reactor water level information that will permit the operators to make timely and correct decisions regarding reactor water control requirements. Individual utilities may adopt certain design changes in response to the NRC's request; this decision would be based on the individual utility's operating practices, operator training, and procedures. However, as discussed herein, identification of a common water level reference is not vital to ensure safe reactor operation and consequently, no modification of the current control room water level instrumentation is required on the basis of plant safety considerations.

## INTRODUCTION

This memorandum has been prepared in response to NUREG-0737 Item II.K.3.27, "Common Water Level Reference" for the participating utilities identified in Appendix A. In this item, the NRC identified a concern with the two different reference zeros of the various reactor pressure vessel water level indications. The NRC concern focussed on a potential for operator confusion arising from the two different reference points for the various water level instruments.

General Electric and the BWR Owners' Group have reviewed the BWR water level indication system and believe that no modifications to the current instrumentation are required based on consideration of plant safety. This memorandum provides a detailed description of the typical BWR water level indication system and the reasoning for the two reference zeros of this system.

WATER LEVEL INDICATION

The BWR water level indication system provides the reactor operator and safety systems with information regarding vessel water level. This section summarizes the key features of the indication system. The discussion applies generally to all BWR/3 through 6 units. The number of water level indicators in some of the earlier BWR designs is significantly different from the more recent designs, however, the functional description, assessment of the indication system, and conclusions are applicable to these earlier BWR's.

As described in more detail in NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", the BWR water level instrumentation provides multiple level indications displayed on the reactor control console or nearby panels in full view of the operator. These indications include (typically) three narrow range (normal operating range) level indicators and one narrow range level recorder, two wide range level recorders and one wide range level indicator, one fuel zone level indicator and one fuel zone level recorder, one upset range level recorder and one shutdown range (vessel flooding) level indicator. In addition, multiple indicating trip units provide wide range and narrow range reactor level safety related trip signals and related alarms. Safety, control, and information functions provided by the level instruments include scram, containment isolation, ECCS initiation, RCIC initiation, permissive signals for ADS initiation, feedwater control, recirculation pump shutoff, MSIV closure, level readout, level recording and level alarm functions in the control room for normal, transient and post-accident conditions.

Figure 1 depicts the correspondence of reactor vessel level and level indicator and recorder ranges. As can be seen in the figure, reactor water level indication covers the vessel in overlapping ranges from below the bottom of the active fuel to the top of the vessel.

There are several water levels of major importance at which automatic actions occur. These significant levels and typical corresponding actions are described in Table 1 and are shown on Figure 1 for approximate correlation. All trip functions and alarms are provided by the narrow or wide range level instruments.

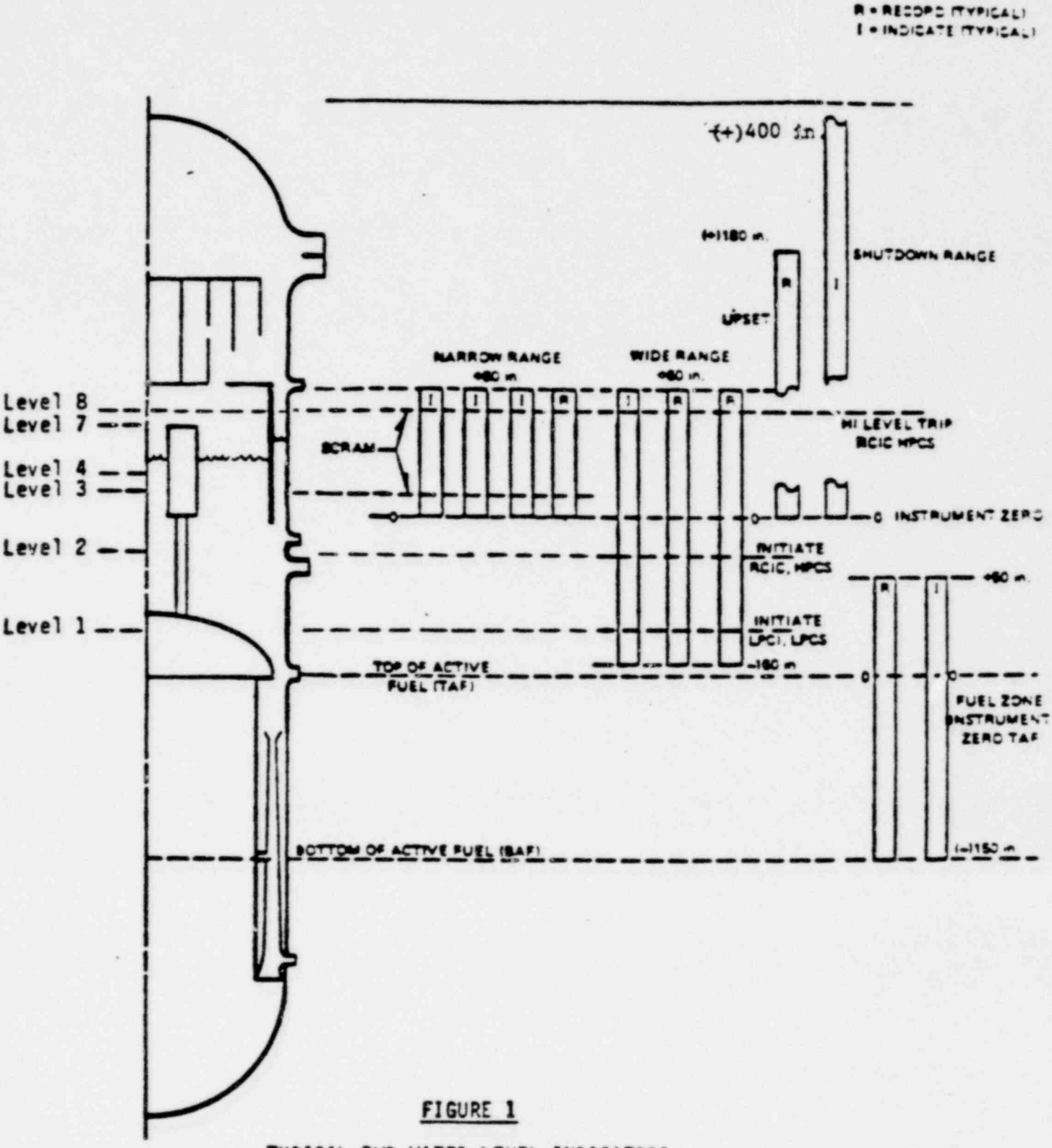



FIGURE 1

TYPICAL BWR WATER LEVEL INDICATORS

ON REACTOR CONTROL PANELS

Table 1

SUMMARY OF SIGNIFICANT REACTOR VESSEL LEVELS

| Level | Action | Approximate Elevation Above TAF (ft) |
|---|---|---|
| Level 8 | Main Turbine Stop Valve Closure, HPCI/HPCS Injection Terminated, Trip RCIC Turbine, Trip Reactor Feedwater Pumps and Condensate Booster Pumps, Scram (run mode only) | 18-1/2 |
| Level 7 | Alarm | 17 |
| | Operating Reactor Level is Maintained Below the High Level Alarm and Above Low Level Alarm. | |
| Level 4 | Alarm, Run Back Recirculation Flow on Loss of One Feed Pump. | 16 |
| Level 3 | Scram and Run Back Recirculation Flow, Permissive for ADS, Close RHR Shutdown Isolation Valves. | 14-1/2 |
| Level 2 | Initiate Reactor Core Isolation Cooling System, Division 3 Diesel Generator and High Pressure Core Spray System, Close Isolation Valves, Except RHR Shutdown Isolation Valves and MSIV's, Shutdown Recirculation System. | 11 |
| Level 1 | Initiate Residual Heat Removal Pumps and LPCS, Start Division 1 and 2 Diesel Generators, Close MISV's and Initiate ADS (in conjunction with other signals.) | 1-1/2 |
| Top of Active Fuel | | 0 |
| Bottom of Active Fuel | Fuel Zone Indication | -12-1/2 |

FUNCTIONAL DESCRIPTION

All instrumentation, except the fuel zone instruments have a common reference zero.

All instrumentation, except the shutdown and fuel zone instruments, are calibrated based on normal power operating pressure and temperature conditions. The shutdown and fuel zone instruments are calibrated based on depressurized reactor conditions consistent with their functions.

The BWR water level indication scheme is based on two reference levels: one close to the bottom of the dryer skirt* for normal operation, upset and shutdown events, and one close to the top of the active fuel*. Four of the five instrument ranges (narrow, wide, upset, and shutdown ranges) have indicator and recorder scales which share the bottom of the dryer skirt as a common reference zero. Only the fuel zone instrument's scales are based on zero located at the top of the active fuel.

The narrow range instrumentation is provided to monitor and control reactor water level during normal power operating conditions. The reference point to the bottom of the dryer skirt is selected based on normal plant operation considerations. Specifically, high water level decreases the quality of steam delivered from the reactor due to degraded separator performance. Low water level that would permit passage of wet steam from the reactor due to inadequate skirt submergence could likewise potentially damage the main turbine and feedwater turbine. Hence a reference location relative to the bottom of the dryer skirt is appropriate. In addition to controlling water level during plant operation, the narrow range instrumentation also provides high and low water scram signals and ADS low level signals.

The wide range instruments are provided are provided as an extension of the narrow range to cover abnormal operating transients. The wide range scale encompasses the setpoints for initiation of HPCI/RCIC and low pressure ECCS and provides initiation signals for ADS and isolation systems. These instruments are calibrated for normal power operating pressure and temperature conditions to assure proper initiation of safety frunctions and to avoid

*Throughout this memorandum, "bottom of the dryer skirt" refers to a location near the bottom of the dryer skirt. Similarily, "top of the active fuel" refers to an elevation at or somewhat above the top of the active fuel.

inadvertent scram or increased spurious signals that would jeopardize normal plant operations and result in reactor unavailability. For consistency, their zero reference is the same as that for narrow range instruments.

The upset range instrumentation is an upward extension of the normal range. It is provided to monitor unusually high water level transients that can be postulated to occur during reactor operation. Its reference zero is the same as the narrow-range instrumentation.

The shutdown range is used for monitoring the reactor water level under shutdown conditions when the reactor is depressurized and flooded, prior to vessel head removal. For consistency, its reference zero is the same as the narrow range instrumentation.

Fuel zone level instrumentation is provided to indicate reactor water level following a large break LOCA (such as a double ended recirculation line break) and to verify core reflood by ECCS. It is not intended to give meaningful indication under any other plant transient or operating conditions or when the reactor is pressurized. Since the only function of the fuel zone instrumentation is to monitor level after a large loss of coolant accident, its zero reference location is selected as the top of the active fuel.

As indicated by the above discussion, the level instrumentation, calibration, location and scale ranges are based on the intended utilization and function of the instruments. It is evident, then, that there already exists an overall common water level reference for all normal operating and accident conditions except the large break LOCA, and that the water level zero reference for the large break LOCA differs from the others for a good reason.

This different reference level for the fuel zone level instrumentation is not confusing to the operator because he is familiar with the difference as a result of training and experience. The operator's awareness of the difference is constantly reinforced during routine control room surveillance since the fuel zone level is always off scale high and is adjacent to the wide range level instruments which are on scale.

Since the instruments, the calibration, and ranges are based on specific, well defined and logical functional criteria, operator confusion should not occur.

ASSESSMENT

To respond to the NRC's concern regarding a common water level reference, General Electric and the BWR Owners Group have reviewed the BWR water level indication system, giving attention to the following considerations:

- Responsiveness to the NRC's requirement
- Impact on safe reactor operation
- Compatibility with human factors concepts

The BWR water level instrumentation is based on an overall common reference zero for all normal operation, transient and accident conditions except the large break LOCA.

This design is based on the philosophy that the bottom of the dryer skirt is the most significant vessel elevation for normal, upset, and most postulated accident conditions. For the case of abnormal, diminishing water level, the trip functions automatically initiate emergency core coolant injection systems. With the redundancy of emergency systems available the reactor water level will generally not decrease to the top of the fuel for a large spectrum of accidents and transients. Further, the reactor operator's primary concern when in any decreasing low water level condition is to act so as to raise the water level. Any quantitative knowledge of the water level is much less significant than the fundamental and paramount task of restoring water level to near normal.

The fuel zone instrument, with its reference point (zero) at the top of the active fuel, becomes important for large design basis LOCAs as the primary verification of level. It provides secondary verification of level for small break LOCAs that ECCS has performed effectively. Correlation of this instrument with the bottom of the dryer skirt is not necessary.

CONCLUSION

General Electric and the BWR Owners' Group have concluded that the current BWR water level indication system is fully adequate to allow plant operators to respond properly under all postulated reactor conditions, and that there are no required design changes based on any plant safety considerations. Individual utilities may adopt certain design changes in response to the NRC request, this decision would be based on the individual utility's operating practices, operator training and procedures.

## II.K.3.28 Study and Verify Qualification of Accumulators on ADS Valves

### NRC Position

Safety analysis reports claim that air or nitrogen accumulators for the ADS valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated 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.

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

### LILCO Position

There are four modes of supplying air to the SRV's (normal operation, short term supply, intermediate term supply, and long term supply). During normal operation, air is supplied to the short term and intermediate term accumulators. Air is retained in these accumulators by check valves so they remain pressurized during this mode.

In the event of an abnormal condition and before valve changeover is completed, the short term accumulators on each SRV will supply air sufficient for at least five actuations of each SRV. Each accumulator also has sufficient pressure (>25 psig) to maintain the valve open after five actuations. The valve changeover from short to intermediate term mode occurs within minutes, so that effects of valve operator leakage, during the short term mode, are minimal.

For the intermediate term supply mode, in addition to any air remaining in the short term accumulators, the two intermediate term accumulators are each capable of supplying air sufficient for at least 55 additional SRV actuations for a minimum of 48 hours, including the maximum allowable leakage from all eleven SRV operators. These accumulators are sized by extending the short term accumulator sizes and compensating for total SRV operator leakage over 48 hours from vendor furnished maximum leakage rates.

The accumulator and connected piping are designed to ASME III Class 2 requirements and contain no active components other than the in-line check valves which may perform an isolation function and a Class 1E powered motor operated valve which provides intermediate and long-term ADS supply air. The stainless steel construction of the accumulators and piping is not subject to failure during hostile environmental conditions. Valve leakage has been accounted for and is not of concern during long-term conditions.

Beyond 48 hours the long term mode uses an air connection outside of the reactor building for replenishing the air supply. This air connection and connecting piping is also designed to ASME III Class 2 requirements. A portable compressor, or air/nitrogen bottles may be connected to the system to sustain SRV operability indefinitely.

## II.K.3.44 Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure

### NRC Position

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

### BWR Owners' Group Discussion

Analyses have been performed for the worst anticipated transient of those identified in R.G. 1.70 (loss of feedwater event) with the worst single active failure (loss of HPCI) which demonstrate that the reactor core remains covered with water until stable conditions are achieved. Analyses have also been performed for further degraded conditions involving a stuck-open relief valve in addition to the worst transient and single failure. The results of these analyses show that, with proper operator action, the core remains covered. For a complete discussion of the Owners' Group response, refer to Attachment 1, "BWR Owners' Group Evaluation of NUREG-0737 Item II.K.3.44."

### BWR Owners' Group Implementation Criteria

No implementation criteria are applicable for this item.

### LILCO Position

LILCO endorses the result of analyses described in Attachment 1 demonstrating that the core remains covered for the worst anticipated transient (loss of feedwater) with the worst single active failure (loss of HPCI). LILCO also endorses the results of additional analyses demonstrating the capability to keep the core covered for the conditions described above in combination with a stuck-open relief valve. For supporting documentation, refer to Attachment 1.

# BWR OWNERS' GROUP EVALUATION OF

# NUREG-0737 ITEM II.K.3.44

# ADEQUATE CORE COOLING FOR TRANSIENTS WITH

# A SINGLE FAILURE

Table of Contents

Summary

Analyses 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) were performed to demonstrate adequate core cooling capability. It is shown that, for the BWR/2 through BWR/6 plants, adequate core cooling is maintained for these worst-case conditions. Analyses of further degraded conditions involving a stuck-open relief valve in addition to the worst transient and single failure were also performed. The results show that, with proper operator action, the core remains covered and therefore adequate core cooling is achieved.

# ADEQUATE CORE COOLING FOR TRANSIENTS WITH A SINGLE FAILURE

## I. Introduction

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

> "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."

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

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

the high pressure ECCS or one isolation condenser (IC) loop, whichever is applicable.

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

## II. Criteria, Scope and Assumptions

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

1. The reactor core remains covered with water until stable conditions are achieved; or

2. No significant fuel damage results from core uncovery.

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

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

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

c. The single failure is interpreted as an <u>active</u> failure.

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

## III. Discussion

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

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

b. Steam release paths causing rapid reactor coolant inventory loss, e.g., S/RV's, turbine, or turbine bypass valves.

c. Power level, especially the timing of scram.

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

## TABLE 1

## SUMMARY OF INITIATING TRANSIENTS

(Reference: NRC Regulatory Guide 1.70, Revision 3)

1. Loss of Feedwater Heating
2. Feedwater Controller Failure - Maximum Demand
3. Pressure Regulator Failure - Open
4. Inadvertent Safety/Relief Valve Opening
5. Inadvertent Residual Heat Removal (RHR) Shutdown Cooling Operation
6. Pressure Regulator Failure - Closed
7. Generator Load Rejection
8. Turbine Trip
9. Main Steam Isolation Valve (MSIV) Closure
10. Loss of Condenser Vacuum
11. Loss of Normal AC Power
12. Loss of Feedwater Flow
13. Failure of RHR Shutdown Cooling
14. Recirculation Pump Trip
15. Recirculation Flow Control Failure - Decreasing Flow
16. Rod Withdrawal Error
17. Abnormal Startup of Idle Recirculation Pump
18. Recirculation Flow Control Failure - Increasing Flow
19. Fuel Loading Error
20. Inadvertent Startup of High Pressure Core Spray (HPCS) or High Pressure Coolant Injection (HPCI) or Feedwater Coolant Injection (FWCI) or Isolation Condenser (IC), whichever is applicable.

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

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

1. Failure of HPCI or HPCS or FWCI or one IC loop, whichever is applicable.

2. Failure of RCIC.

3. One of the S/RV's, which has opened as a result of the transient, fails to close.

Items 1 and 2 are the possible limiting failures because they represent loss of high pressure inventory makeup or heat removal systems which would be relied on following a loss of feedwater event. Item 3 is a possible limiting failure, because it results in the largest steam release rate from the vessel compared to other possible release paths (e.g., a stuck-open turbine bypass valve). No other failures identified in Table 2 result in a direct challenge to core cooling capability.

## TABLE 2

## LIST OF SINGLE FAILURES WHICH CAN POTENTIALLY DEGRADE THE COURSE OF A BWR TRANSIENT

1. One or all of the bypass valves fail to modulate open when required.

2. One of the bypass valves, which has opened as a result of the transient, fails to close.

3. Failure to trip the turbine or feedwater pumps on high water level.

4. One main steam isolation valve (MSIV) fails to close when required.

5. One of the safety/relief valves fails to open when required.

6. One of the safety/relief valves, which has opened as a result of the transient, fails to close.

7. Failure to trip one recirculation pump.

8. Failure to run back the recirculation pumps.

9. Failure of high pressure coolant injection (HPCI) or high pressure core spray (HPCS) or feedwater coolant injection (FWCI) or one isolation condenser (IC) loop, whichever is applicable.

10. Failure of reactor core isolation cooling (RCIC) or one IC loop, whichever is applicable.

11. Failure of one low pressure coolant injection (LPCI) loop or the low pressure core spray (LPCS) system.

TABLE 2 (CONT'D)

12. Loss of one residual heat removal (RHR) system heat exchanger.

13. A single control rod stuck while the remainder of the control rods are moving.

14. Failure to achieve the rod block function (i.e., a single control rod will withdraw upon erroneous withdrawal demand).

15. Loss of one diesel generator if loss of AC power was the initiating event.

Because of the relatively low steam loss capacity through one SORV (Failure 3, Page 5) compared to the makeup water capacity of the highest capacity makeup water system, the failure of the highest capacity high pressure makeup system (Failure 1, Page 5) would be worse than a stuck open relief valve (Failure 3, Page 5). For example, for a typical BWR/4, representative values of HPCI makeup and S/RV flow are 18% and 6% of rated feedwater flow, respectively. Because of the higher makeup rate of HPCI/HPCS relative to RCIC (3% of rated feedwater flow), Failure 1 would be worse than Failure 2. Table 3 lists the worst combination of transient and single failure for the GE BWR product lines covered by this study.

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

With even more degraded conditions, i.e., one SORV in addition to the worst case transient with the worst single failure, reference plant analyses in Reference 1 Tables 3.2.1.1.5-9 and 3.2.1.1.5-10 show that for the plants analyzed the RCIC system can automatically provide sufficient inventory to keep the core covered even with a single failure plus a SORV. This capability is not a design basis for the RCIC system, and not all plants have been analyzed to demonstrate this capability. If a plant should not have this

## TABLE 3

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

| Product Line | Transient with a Single Failure (The Worst Case) |
|---|---|
| BWR/2 | LOF + Failure of one IC Loop (Oyster Creek only)<br>LOF + Failure of FWCI (Nine Mile Point only) |
| BWR/3 | LOF + Failure of FWCI (Millstone only)<br>LOF + Failure of HPCI (others) |
| BWR/4 | LOF + Failure of HPCI |
| BWR/5 | LOF + Failure of HPCS |
| BWR/6 | LOF + Failure of HPCS |

capability, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV. It should be noted that manual depressurization is the proper operator action for all plants during loss of inventory conditions when the high pressure cooling system(s) are unable to restore and maintain RPV level. These proper operator actions are allowed for in the NUREG-0737 requirement.

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

## IV. Conclusion

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

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

It is concluded that for anticipated transients combined with the worst single failure the core remains covered. Additionally, it is concluded that for severely degraded transients beyond the design

basis where it is assumed that a S/RV sticks open and an additional failure occurs the core remains covered with proper operator action.

## V. References


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

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

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

## APPENDIX A

## PARTICIPATING UTILITIES

## NUREG-0737, II.K.3.44

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

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

## II.K.3.45 Evaluation of Depressurization With Other Than Full ADS

### NRC Position

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

### BWR Owners' Group Discussion

It has been demonstrated that a full ADS blowdown does not cause the stress limits for vessel integrity to be exceeded. In addition, reduced depressurization rates do not significantly decrease fatigue usage of the reactor vessel and core support structure. On the contrary, reduced depressurization rates can have an adverse effect on core cooling capability by allowing the core to become uncovered for longer periods of time. For a complete discussion of the Owners' Group position, refer to Attachment 1, "BWR Owners' Group Evaluation of NUREG-0737 Item II.K.3.45."

### BWR Owners' Group Implementation Criteria

Since a full ADS blowdown is well within the design basis of the reactor pressure vessel and ADS is properly designed to minimize the challenge to core cooling, no change in depressurization rate is required.

### LILCO Position

LILCO endorses the position of the BWR Owners' Group that reduced depressurization rates are not necessary from the standpoint of safety to ensure reactor vessel integrity. For supporting documentation, refer to Attachment 1.

ATTACHMENT 1

# BWR OWNERS' GROUP EVALUATION OF

# NUREG-0737 ITEM II.K.3.45

# ALTERNATE MODES OF DEPRESSURIZATION

## TABLE OF CONTENTS

## SUMMARY

Analyses of depressurization rates other than full ADS were performed to determine the effect on reactor vessel integrity and core cooling capability. It is shown that:

1. Vessel integrity limits are not exceeded for full ADS blowdown,

2. For slower depressurization rates, there is little benefit on vessel fatigue usage relative to full ADS blowdown, and

3. Slower depressurization rates can have an adverse impact on core cooling capability.

## I. Introduction

The feasibility study reported herein addresses NUREG-0737 item II.K.3.45 which states,

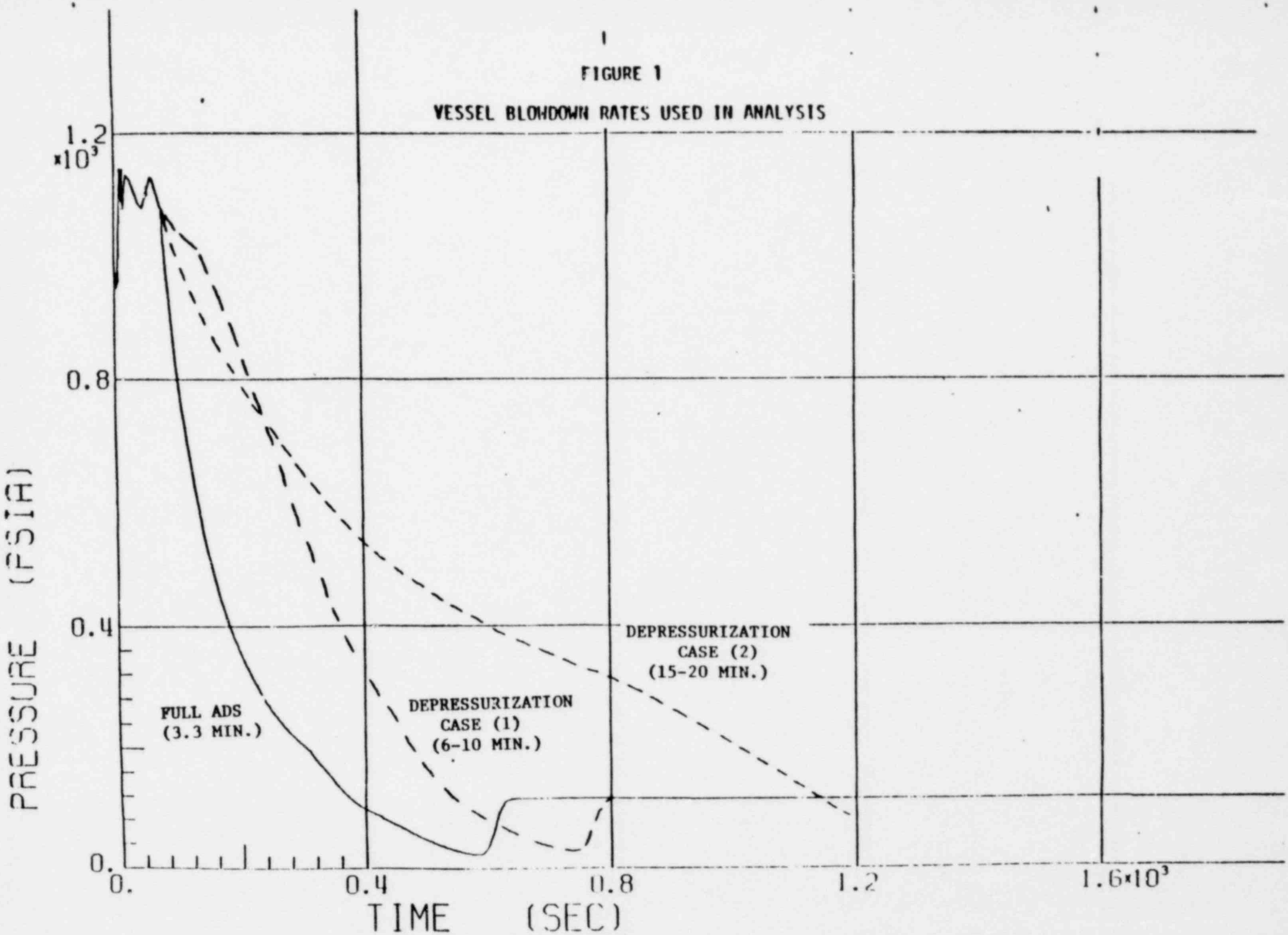
> "Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRV's) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown".

An evaluation of alternate modes of depressurization other than full actuation of the Automatic Depressurization System (ADS) is made for the plants listed in Appendix A with regard to the effect of such reduced depressurization rates on core cooling and vessel integrity.

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

FIGURE 1

VESSEL BLOWDOWN RATES USED IN ANALYSIS



## II. Assumptions

The major assumptions used for the core cooling analysis are:

1. No high pressure cooling systems are available.

2. All low pressure ECC systems are available.

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

## III. Results

### A. Vessel Integrity

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

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

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

B. Core Cooling Capability

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

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

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

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

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

## IV. Discussion

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

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

1. Inventory in the core and lower plenum at the time of low pressure ECCS injection as predicted by the SAFE[1] model.

2. The total time which the top of the active fuel (TAF) remains uncovered as predicted by the SAFE[1] model.

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

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Ref. 1 NEDO-24708 "Additional information required for NRC Staff Generic Report on Boiling Water Reactors", August, 1979.

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

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

## V. Conclusion

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

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

TABLE 1

RESULTS FOR BWR/6 OUTSIDE STEAMLINE BREAK
NO HIGH PRESSURE SYSTEMS AVAILABLE

| DEPRESSURIZATION CASE | DEPRESSURIZATION INITIATION LEVEL | DEPRESSURIZATION INITIATION TIME (SEC) | CORE UNCOVERED TIME (SEC) | LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS) |
|---|---|---|---|---|
| FULL ADS | TAF* | 1086 | 26 | $1.603 \times 10^5$ |
| CASE 1 | TAF | 1086 | 117 | $1.528 \times 10^5$ |
| CASE 1 | 34' | 610.6 | 10 | $1.779 \times 10^5$ |
| FULL ADS | Level 2† + 60 Sec. | 78.3 | No Uncovery | $1.993 \times 10^5$ |
| CASE 1 | Level 2 + 60 Sec. | 78.3 | No Uncovery | $1.937 \times 10^5$ |
| CASE 2 | Level 2 + 60 Sec. | 78.3 | 390 | $1.755 \times 10^5$ |

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE 2

RESULTS FOR BWR/6 STUCK-OPEN RELIEF VALVE
NO HIGH PRESSURE SYSTEMS AVAILABLE

| DEPRESSURIZATION CASE | DEPRESSURIZATION INITIATION LEVEL | DEPRESSURIZATION INITIATION TIME (SEC) | CORE UNCOVERED TIME (SEC) | LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS) |
|---|---|---|---|---|
| FULL ADS | TAF* | 642.6 | No Uncovery | $1.836 \times 10^5$ |
| CASE 1 | TAF | 642.6 | 15 | $1.787 \times 10^5$ |
| CASE 1 | 34' | 391.8 | No Uncovery | $1.889 \times 10^5$ |
| CASE 1 | Level 2 † + 60 Sec. | 77.7 | No Uncovery | $1.961 \times 10^5$ |

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE 3

RESULTS FOR BWR/3 OUTSIDE STEAMLINE BREAK
NO HIGH PRESSURE SYSTEMS AVAILABLE

| DEPRESSURIZATION CASE | DEPRESSURIZATION INITIATION LEVEL | DEPRESSURIZATION INITIATION TIME (SEC) | CORE UNCOVERED TIME (SEC) | LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS) |
|---|---|---|---|---|
| FULL ADS | TAF* | 1527.8 | 155 | $2.027 \times 10^5$ |
| CASE 1 | TAF | 1527.8 | 170 | $1.975 \times 10^5$ |
| CASE 1 | 34' | 701.6 | 51 | $2.291 \times 10^5$ |
| FULL ADS | Level 1 † + 60 Sec. | 364.4 | No Uncovery | $2.446 \times 10^5$ |
| CASE 1 | Level 1 + 60 Sec. | 364.4 | 10 | $2.394 \times 10^5$ |

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE 4

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

| DEPRESSURIZATION CASE | DEPRESSURIZATION INITIATION LEVEL | DEPRESSURIZATION INITIATION TIME (SEC) | CORE UNCOVERED TIME (SEC) | LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS) |
|---|---|---|---|---|
| FULL ADS | TAF* | 759.4 | 264 | $1.960 \times 10^5$ |
| CASE 1 | TAF | 759.4 | 277 | $1.913 \times 10^5$ |
| FULL ADS | Level 1 † + 60 Sec. | 145.6 | 175 | $2.210 \times 10^5$ |
| CASE 1 | Level 1 + 60 Sec. | 145.6 | 191 | $2.165 \times 10^5$ |

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

## APPENDIX A

### NUREG-0737 ITEM II.K.3.45

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

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

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

### NRC Position

A series of questions have been posed by Mr. C. Michelson regarding various aspects of PWR and BWR reactor operation. Those pertaining to BWR's address the following topics:

1. Question 2 - Isolation of Small Breaks
2. Question 6 - Recirculation Mode of Operation of High Pressure Coolant Injection (HPCI) pump
3. Question 7 - Simultaneous Operation of HPCI and Residual Heat Removal (RHR) pumps
4. Question 9 - Minimum Flow Protection for HPCI Pumps
5. Question 11 - Impact of Continued Running of Recirculation Pumps During a Small Loss of Coolant Accident (LOCA)
6. Question 12 - Impact of Pump Seal Damage and Leakage During a Small Break LOCA with Loss of Offsite Power
7. Question 14 - Effect of Noncondensable Gas Accumulation
8. Question 15 - Impact and Consequences of Activating the Containment Spray System Following a Small Break LOCA
9. Question 16 - Isolation of a Pipe Break Following LOCA

### BWR Owners' Group Discussion

General Electric has reviewed these questions and prepared responses on behalf of the BWR Owners' Group. These responses are contained in a letter, R. H. Buchholz to D. F. Ross, "Response to Questions Posed by Mr. C. Michelson," February 21, 1980, included as Attachment 1.

### BWR Owners' Group Implementation Criteria

The questions and associated responses have not identified a need for any plant modifications. This section is, therefore, not applicable.

### LILCO Position

LILCO endorses the responses of General Electric as contained in Attachment 1.

Note in Question 12 of Attachment 1, for Shoreham external cooling is required for the RHR pump seals for the shutdown cooling mode only.

ATTACHMENT 1

GENERAL ELECTRIC

NUCLEAR POWER

SYSTEMS DIVISION

GENERAL ELECTRIC COMPANY, 175 CURTNER AVE., SAN JOSE, CALIFORNIA 95125
MC 682, (408) 925-5722
RHB-008-80

MFN-041-80

February 21, 1980

U. S. Nuclear Regulatory Commission
Division of Project Management
Office of Nuclear Reactor Regulation
Washington, D. C. 20555

Attention: D. F. Ross

Gentlemen:

SUBJECT: RESPONSE TO QUESTIONS POSED BY MR. C. MICHELSON

Reference: Letter, D. F. Ross to T. D. Keenan, Information Required to Address Michelson's Concerns for Boiling Water Reactors, 10/17/79

The reference letter requested that the BWR Owners Group review and respond to questions posed by Mr. C. Michelson which were included as Enclosures A and B of the reference. General Electric has reviewed these questions and prepared responses on behalf of the BWR Owners Group. Sixty (60) copies of these responses are enclosed for use by your staff.

Sincerely,

RHBuchholz

R. H. Buchholz, Manager
BWR Systems Licensing
Safety and Licensing Operation

RHB:cas/119-M

Enclosure

cc: BWR Owners Group

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## RESPONSE TO QUESTIONS POSED BY MR. C. MICHELSON

QUESTION 1 Pressurizer level is an incorrect measure of primary coolant inventory.

RESPONSE BWRs do not have pressurizers. BWRs measure primary coolant inventory directly using differential pressure sensors attached to the reactor vessel. Thus, this concern does not apply to BWRs.

QUESTION 2 The isolation of small breaks (e.g., letdown line; PORV) not addressed or analyzed.

RESPONSE Automatic isolation only occurs for breaks outside the containment. Such breaks are addressed in Section 3.1.1.1.2 of NEDO-24708. It was shown that if the high pressure systems are available no operator actions are required. If it is assumed that all high pressure systems fail, the operator must manually depressurize to allow the low pressure systems to inject and maintain vessel water level. Analyses submitted for demonstration of adequate core cooling* show that the operator has sufficient information and time to perform these manual actions. The necessary manual actions have been included in the operator guidelines for small break accidents.

QUESTION 3 Pressure boundary damage due to loadings from a) bubble collapse in subcooled liquid and 2) injection of ECC water in steam-filled pipes.

RESPONSE The BWR has no geometry equivalent to that identified in Michelson's report on B&W reactors relative to bubble collapse (steam bubbling upward through the pressurizer surge line and pressurizer). Thus the first concern is not applicable to BWRs.

ECC injection in the BWR at high pressure is either directly into the reactor vessel (BWR/5-6 HPCS, HPCI on some BWR/4) or into the feedwater lines (FWCI, HPCI on most BWR/3-4). The feedwater lines are normally filled with relatively cold liquid (420°F or less). ECCS injection in the BWR at low pressure is either directly into the reactor vessel (LPCS, BWR/5-6 LPCI) or into the recirculation pump discharge line (BWR/3,4 LPCI) near the automatically-closed recirculation pump discharge valve. Thus the second concern is not applicable to BWRs.

* NEDO-24708 Section 3.5.2.1, which was submitted in prepublication form to D. F. Ross by letter from R. H. Buchholz on November 30, 1979.

QUESTION 4 In determining need for steam generators to remove decay heat, consider that break flow enthalpy is not core exit enthalpy.

RESPONSE BWRs do not use steam generators to remove decay heat, so this concern does not apply to BWRs. The GE modelling of break flow is discussed in NEDO-20566.

QUESTION 5 Are sources of auxiliary feedwater adequate in the event of a delay in cooldown subsequent to a small LOCA?

RESPONSE BWRs do not need feedwater to remove heat from the reactor following a LOCA, whether the subsequent cooldown is delayed or not. Therefore this concern is not applicable to BWRs. BWRs have a closed cooling system in which vessel water flows out the postulated break to the suppression pool. The suppression pool is cooled and water is pumped back to the vessel with ECCS pumps.

QUESTION 6 Is the recirculation mode of operation of the HPCI pumps at high pressure an established design requirement?

RESPONSE The high-pressure injection systems utilized in the BWR's are the Reactor Core Isolation Cooling (RCIC), High Pressure Coolant Injection (HPCI) and High Pressure Core Spray (HPCS).

BWR/1 and 2 units do not have special-purpose high-pressure safety injection systems, such as HPCI and RCIC.* Some BWR's 3 and all BWR's 4, 5, and 6 are provided with RCIC systems. Some BWR's 3 and all BWR's 4 are provided with HPCI systems. BWR's 5 and 6 are provided with HPCS systems. The RCIC and HPCI are steam turbine driven variable speed systems. The HPCS is an electrically driven constant speed system.

The RCIC, HPCI and HPCS systems normally take suction from the condensate storage tank and have an alternate suction source from the suppression pool. A recirculation mode of operation of these systems is established when the system suction is from the suppression pool. Following a LOCA when system suction is from the suppression pool, water injected into the reactor is discharged through the break and flows back to the suppression pool forming a closed recirculation loop.

Other recirculation modes include test modes (e.g., suction from and discharge to the condensate storage tank) and system operation on low flow bypass with discharge to the suppression pool.

All of these modes are established design requirements.

* One unit is installing a high-pressure injection system -- it is not yet in service.

QUESTION 7 Are the HPCI pumps and RHR pumps run simultaneously? Do they share common piping?/suction? If so, is the system properly designed to accommodate this mode of operation (i.e., are any NPSH requirements violated, etc...?)

RESPONSE As noted in response to Question No. 6, BWR/1 and 2 units do not have special-purpose HPCI or RCIC systems.

For BWR/3-6 the high-pressure injection systems (RCIC/HPCI/HPCS) do not share any common suction piping with the RHR, Low Pressure Coolant Injection (LPCI), or low-pressure core spray systems, and they can operate simultaneously with these low pressure systems.

The RCIC/HPCI and RCIC/HPCS systems, on some BWR's, share a common suction line from the condensate storage tank. Many of the BWR LPCI pumps (LPCI on most BWR's is a subsystem of the RHR) and low pressure core spray (CS) pumps share common suction piping. The RHR shutdown cooling operating mode does not share any common suction piping with the RCIC, HPCI, HPCS, CS/LPCS systems. It is an established design requirement to size the suction piping, including shared piping, such that adequate NPSH is available to RCIC, HPCI, HPCS, RHR/LPCI, and CS pumps for all simultaneous operating modes of these systems.

Pre-operational and/or startup tests are conducted that demonstrate that the requirement is met.

QUESTION 8 Mechanical effects of slug flow on steam generator tubes needs to be addressed (transitioning from solid natural circulation to reflux boiling and back to solid natural circulation may cause slug flow in the hot leg pipes.)

RESPONSE BWRs do not have steam generators so this concern does not apply to BWRs. BWR post-LOCA cooling modes are addressed in NEDO-24708.

QUESTION 9 Is there minimum flow protection for the HPCI pumps during the recirculation mode of operation?

RESPONSE As noted in response to Question No. 6, BWR/1 and 2 units do not have special purpose HPCS or RCIC systems.

For BWR/3-6, the RCIC, HPCI, HPCS, RHR, and CS/LPCS pumps all contain valves, piping, and automatic logic that bypasses flow to the suppression pool as required to provide minimum flow protection for all design basis operating modes of the systems.

QUESTION 10 The effect of the accumulators dumping during small break LOCAs is not taken into account.

RESPONSE BWRs do not use accumulators to mitigate LOCAs. Therefore this concern does not apply to BWRs.

QUESTION 11 What is the impact of continued running of the RC pumps during a small LOCA?

RESPONSE The impact of continued running of the recirculation pumps has been addressed in Sections 3.3.2.2, 3.3.2.3, and Section 3.5.2.1.5.1 of NEDO-24708.* The conclusions were that continued running of the recirculation pumps results in little change in the time available for operator actions and does not significantly change the overall system response.

QUESTION 12 During a small break LOCA in which offsite power is lost, the possibility and impact of pump seal damage and leakage has not been evaluated or analyzed.

RESPONSE The RCIC, HPCI, HPCS, RHR, CS/LPCS pumps are provided with mechanical seals. These seals are cooled by the pump primary process water. No external cooling from auxiliary support systems, such as site service water or room air coolers, is required for pump seals. These types of seals have demonstrated (in nuclear and other applications) their capability to operate for extended periods of time at temperatures in excess of those expected following a LOCA.

Should seal failure occur it can be detected by room sump high level alarms. The RCIC, HPCI, HPCS, LPCS and CS and RHR individual pumps are arranged, and motor operated valves provided, so that a pump with a failed seal can be shutdown and isolated without affecting the proper operation of the other redundant pumps/systems.

Considering the low probability of seal failure during a LOCA, the fact that a pump with a failed seal can be isolated without affecting other redundant equipment, and the substantial redundancy provided in the BWR emergency cooling systems, pump seal failure is not considered a significant concern.

* The latter section was transmitted in prepublication form to D. F. Ross by letter from R. H. Buchholz on November 30, 1979.

QUESTION 13 During transitioning from solid natural circulation to reflux boiling and back again, the vessel level will be unknown to the operators, and emergency procedures and operator training may be inadequate. This needs to be addressed and evaluated.

RESPONSE There is no similar transition in the BWR case. In addition, the BWR has water level measurement within the vessel and the indication of the water level is incorporated into the operator guidelines. Consequently this concern does not apply to BWRs.

QUESTION 14 The effect of non-condensible gas accumulation in the steam generators and its possible disruption of decay heat removal by natural circulation needs to be addressed.

RESPONSE The effect of non-condensible gas accumulation is addressed in Section 3.3.1.8.2 of NEDO-24708. For a BWR, vapor is present in the core during both normal operation and natural circulation conditions. Non-condensibles may change the composition of the vapor but would have an insignificant effect on the natural or forced circulation itself, since the non-condensibles would rise with the steam to the top of the vessel after leaving the steam separators.

CONCERN 15 Delayed cooldown following a small break LOCA could raise the containment pressure and activate the containment spray system. Impact and consequences need addressing.

RESPONSE

A. Mark I and II Containments:

Except for a few early plants, most plants with Mark I and II containments do not have an automatically initiated drywell or wetwell spray. Only one of the newer plants (not yet operating) has an automatic wetwell spray.

It is very unlikely that the operator would manually initiate drywell sprays even given that a LOCA has occurred. Some non-essential equipment in the drywell (e.g., recirculation pumps) could be adversely affected by drywell spray. All essential equipment in the drywell has been qualified for the steam and temperature environment that would exist following a LOCA.

There is no equipment in the wetwell that is adversely affected by wetwell sprays.

B. Mark III Containments:

There is no drywell spray in a Mark III containment.

There is an automatic spray system in the wetwell (containment). All essential equipment has been qualified for this condition.

QUESTION 16* This concern relates to the possibility that an operator may be inclined and perhaps even trained to isolate, where possible, a pipe break LOCA without realizing that it might be an unsafe action leading to high pressure, and short-term core bakeout. For example, if a BWR should experience a LOCA from a pressure boundary failure somewhere between the pump suction and discharge valve for either reactor recirculation pump, it would be possible for the operator to close these valves following the reactor blowdown to low pressure and thereby isolate the break, stop the blowdown, and repressurize the reactor coolant system. Before such isolation should be permitted, it is first necessary to show by an appropriate analysis that the high pressure ECCS is adequate to reflood the uncovered core without assistance from the low pressure ECCS which can no longer deliver flow because of the repressurization. Otherwise, such isolation action should be explicitly forbidden in the emergency operating instructions.

RESPONSE If a BWR should experience a LOCA from a pressure boundary failure somewhere between the recirculation pump suction and discharge valves, it is possible for the operator to close these valves following the reactor blowdown to low pressure and thereby isolate the break. In Reference 2, the NRC concluded based on information provided by GE that recirculation break isolation is not a problem.

In order for the reactor vessel to repressurize following isolation of a recirculation line break, the isolation would have to occur before initiation of ADS due to a high drywell pressure in concurrence with low water level 1 condition. Isolation of a recirculation line break prior to obtaining a high drywell pressure signal might occur for very small breaks (area $<< 0.01\ ft^2$) which may require several hundred seconds following the break to reach the high drywell pressure set point. In this case it has been shown in Reference 3 that the high pressure systems (RCIC, HPCI/HPCS, feedwater, and CRD) are sufficient to maintain the water level above the top of the core.

*Excerpt from Reference 1.

If isolation of the recirculation break were to occur prior to reaching level 1 but after the high drywell pressure signal the vessel would pressurize to the SRV set point following isolation of the main steam lines and then oscillate as the SRVs cycle open and closed. If no high pressure systems were available, the loss of mass out the SRVs would cause the level to continue dropping and result in automatic ADS actuation shortly after reaching level 1. This would depressurize the vessel and allow the low pressure systems to begin injecting. This capability was demonstrated in analyses presented in Reference 3. The small-break operator guidelines in NEDO-24708, in addition, explicitly provide for manual depressurization in the event of low reactor water level with high pressure systems unable to maintain level for any reason.

In summary, in order to repressurize the vessel following recirculation break isolation, the isolation would have to occur prior to ADS blowdown. For these cases, high pressure systems would maintain inventory and it has been shown that no adverse consequences result from isolation of a break in the recirculation line.

REFERENCES:


1. Memo, C. Michelson to D. Okrent, "Possible Incorrect Operator Action Such as Pipe Break Isolation," June 4, 1979.

2. Letter, D. G. Eisenhut to R. L. Gridley, "Potential for Break Isolation and Resulting GE-Recommended BWR/3 ECCS Modifications," June 14, 1978.

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