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SUPPLEMENT 10 TO NUREG-0933
"A PRIORITIZATION OF GENERIC SAFETY ISSUES"
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INTRODUCTION

I. BACKGROUND

History

On October 8, 1976, the Commission directed the staff to develop "a program plan for resolution of generic issues and completion of technical projects." The Commission further requested that "this plan should include: task schedules ... task priority and manpower requirements (with proportions of staff contract efforts explicitly identified)." On December 12, 1977, the Energy Reorganization Act of 1974 was amended by Congress through Public Law 95-209 to include, among other things, a new Section 210 as follows:

UNRESOLVED SAFETY ISSUES PLAN

> Sec. 210. The Commission shall develop a plan providing for specification and analysis of unresolved safety issues relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plan shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter.

In order to meet both Commission and Congressional directives, the staff developed a generic issues program that provided for the identification of generic issues, the assignment of priorities, the development of detailed action plans, projections of dollar and manpower costs, continuous high level management oversight of progress, and public dissemination of information related to the issues as they progressed. This program was published in NUREG-0410[387] in January 1978 and, shortly thereafter, the Commission issued a Policy Statement[1190] on the NRC "Program for Resolution of Generic Issues Related to Nuclear Power Plants."

The NRC generic issues program published in NUREG-0410[387] was considerably broader than the "Unresolved Safety Issues Plan" required by Section 210. It included plans for the resolution of generic environmental issues, for the development of improvements in the reactor licensing process, and for consideration of less conservative design criteria or operating limitations in areas where existing requirements might be unnecessarily restrictive or costly.

The first attempts by the staff to implement the generic issues program stated in NUREG-0410[387] were based largely on engineering judgments. This qualitative effort to rank unresolved generic issues continued through two phases:

(1) In 1977, all issues were classified into four categories according to importance, from "significant" to "little or no importance."

(2) In the early part of 1978, the issues were reclassified into Groups 1 through 8 by type rather than by order of importance.

Later in 1978, the staff began to take a quantitative approach by using risk assessment to place the issues into four categories ranging from I (potential high risk items) to IV (items not directly related to risk). With increased confidence in this risk assessment approach, the staff introduced a more comprehensive quantitative system in early 1979. Points were assigned to each issue based on an assessment of safety significance, environmental significance, licensing effectiveness, deadline pressure, and retrofit versus forward-fit. Although the point system was still quite subjective, it was nevertheless a major improvement over the previous methods used.

In the aftermath of the Three Mile Island Unit 2 (TMI-2) accident, many new generic issues were raised and the staff came to the conclusion that the point system was too subjective to be used for ranking the issues. One of the TMI Action Plan[48] items, IV.E.2, called for the staff to develop a plan for the early resolution of safety issues. It was in resolving this issue that the staff developed a quantitative "prioritization" methodology whereby a numerical priority score could be assigned to each generic safety issue. With this approach, priorities were to be based on an evaluation of the estimated risk reduction associated with the potential change in requirements that could result from resolution of an issue and the estimated costs to the NRC and the industry in implementing such a change. This methodology was submitted to the Commission for information in SECY-81-513.[1] In April 1983, this approach was refined and resubmitted to the Commission for approval in SECY-83-221.[1188] After Commission review, approval to use the methodology was given in November 1983.[1189]

Operating Plan

The initial work in prioritizing issues was essentially done by various Staff Working Groups. Following a reorganization of the Office of Nuclear Reactor Regulation (NRR) in April 1980, the lead responsibility for prioritization was assigned to the Safety Program Evaluation Branch, Division of Safety Technology, Office of Nuclear Reactor Regulation (SPEB/DST/NRR).

The 1983 NRC Policy and Planning Guidance (NUREG-0885, Issue 2),[210] in addressing the area of Coordinating Regulatory Requirements (Planning Guidance, Item 5, p.6) called for "...a priority list of generic safety issues including TMI-related issues based on the potential safety significance and cost of implementation of each issue..." to be submitted to the Commission for approval. Using the prioritization methodology outlined below, this list was developed by SPEB in response to the Planning Guidance and forwarded to the Commission in SECY-83-221.[1188]

After another NRR reorganization in November 1985, this task was assigned to the Safety Program Evaluation Branch, Division of Safety Review and Oversight (SPEB/DSRO/NRR). Following an NRC reorganization in April 1987, the responsibility for preparing and maintaining the list of generic safety issues and their priority was assigned to the Advanced Reactors and Generic Issues Branch, Division of Regulatory Applications, Office of Nuclear Regulatory Research (ARGIB/DRA/RES).

The prioritization of generic issues is an ongoing staff function that has been reflected annually in the NRC Policy and Planning Guidance.[210] This document was superseded in 1987 by the NRC Five-Year Plan.

II. GENERIC ISSUES PROGRAM

After issuance of the Policy Statement[1190] in 1978, the NRC program to resolve generic issues underwent many reviews and changes. As a result, the Commission concluded in April 1989 that the 1978 Policy Statement no longer reflected the NRC's generic issues program and withdrew it from the public record.[1191] The current generic issues program consists of six separate and distinct steps: identification, prioritization, resolution, imposition, implementation, and verification (See Exhibit A). An explanation of each of these six steps is given below.

Identification

Generic concerns may be identified by individuals or organizations within the NRC staff or by the Advisory Committee on Reactor Safeguards (ACRS), the nuclear power industry, or the public. RES Office Letter No. 1 (OL #1)[1192] provides a procedure and suggested content for individuals or organizational units within the NRC to request consideration of a concern as a new generic issue. This procedure may also be used by parties outside the NRC to express their concerns to the staff for consideration as potential generic issues. Sources of potential generic issues are many and varied and include, but are not limited to, the following: evaluation of safety-related research, risk assessment analyses, and public and industry concerns.

Prioritization

This report focuses on the prioritization step of the generic issues program which is explained in detail in Paragraph III below.

Resolution

After an issue has been prioritized and approved for resolution, the first task is the development of a plan to delineate the work to be done, assignment of major responsibilities, identification of project resource needs, and scheduling of milestone dates. These activities vary in scope and depth in accordance with issue priority and the depth of information on a given issue. The second task involves development of a technical solution. Typically, the information used to resolve an issue comes from experience data, experiments, tests, analyses, and probabilistic risk assessments (PRAs). The results of such work or the technical findings may be published in contractor and staff NUREG reports which are made

GENERIC ISSUES PROGRAM

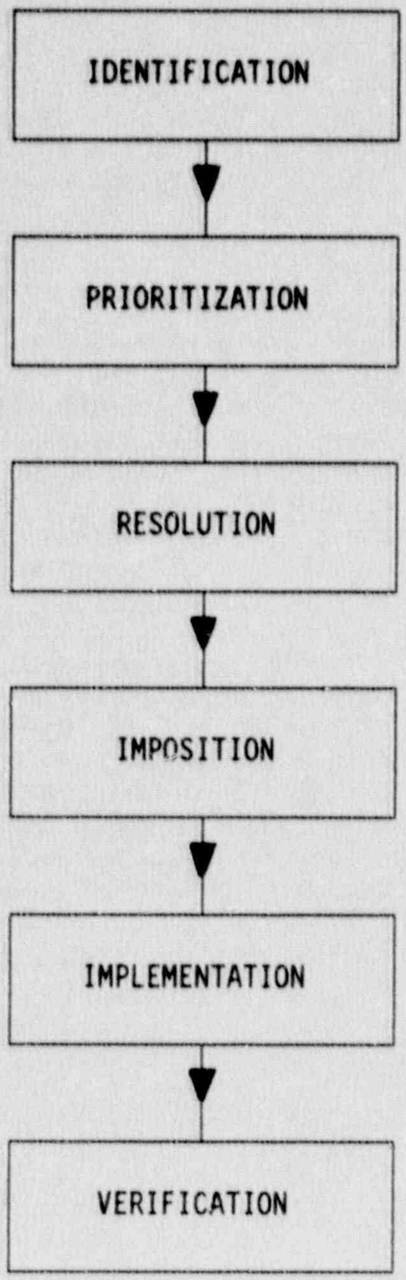

Exhibit A

available through the NRC Public Document Room (PDR), Washington, D.C., or the National Technical Information Service, Department of Commerce, Springfield, Virginia.

In the final stage of resolution, the technical findings are used as a basis to develop a proposed resolution for the issue involving a change to NRC requirements or guidance. Several alternatives may be considered. A regulatory analysis, including a detailed cost/benefit analysis of each practical alternative, and consideration of the best methods of imposition, implementation, and verification are used in selecting a proposed resolution. If a backfit is proposed, first, a determination is made as to whether the backfit is required to provide adequate protection to the health and safety of the public or simply provides for enhancement of public health and safety. If it is determined that the backfit is necessary to provide an adequate level of protection, the backfit will be imposed regardless of the costs to achieve it. If it is determined that the backfit provides for enhancement of public health and safety, a generic analysis is required that treats the nine factors specified in 10 CFR 50.109(c).[197] Once the cognizant NRC Office Directors have agreed to a proposed resolution, it is then forwarded to the Committee for the Review of Generic Requirements (CRGR), the ACRS, the Executive Director for Operations (EDO), and the Commission for review and approval as appropriate. Changes to regulations, Policies, the Standard Review Plan (SRP), and Regulatory Guides are published in the Federal Register for public comment. Comments received are then incorporated, as appropriate, with the final product published in the Federal Register. Resolution of a generic issue can take from several months to a few years depending on the length of time required by the deliberations involved at each of the above steps.

RES Office Letter No. 3[1194] describes the procedure to be followed in the resolution of a generic issue, denotes the required elements of the resolution plan and resolution package, and identifies review procedures and organizational responsibilities for the approval of the resolution of a generic issue. Guidance for the preparation, review, and required content of the regulatory analysis portion of the resolution package is provided in RES Office Letter No. 2.[1193] Milestone information and reporting requirements as well as organizational responsibilities for the tracking of generic issue resolution are provided in OL #1.[1192] All issues scheduled for resolution are tracked through the resolution process by the Generic Issue Management Control System (GIMCS) which is updated quarterly and placed in the PDR.

Imposition

Imposition is the step in the generic issues program where each affected licensee and/or applicant is required to prepare a schedule for implementing the generic issue resolution consistent with a Rule, Policy, Regulatory Guide, generic letter, bulletin, and/or licensing guidance developed during the resolution stage. Normally, NRC requirements, policies, and/or guidance will not provide for NRC consideration of a licensee's modifications prior to their implementation at an affected plant. This facilitates completion of plant modifications to enhance safety within two refueling outages, not to exceed three years after issuance of NRC requirements, policies, and/or guidance. However, in a few exceptional cases, licensees may be required to submit (normally for NRC approval) their plans (including schedules) for plant modifications prior to their implementation. In all cases, licensees will be required to certify in writing to the NRC that plant modifications have been completed.

For the exceptional cases, the staff reviews each applicant's and/or licensee's submittal with regard to proposed modifications to site, equipment, structures, procedures, technical specifications, operating instructions, etc. and schedules proposed for the accomplishment of the modifications. For backfit requirements, imposition is complete when each affected licensee has committed to compliance actions and schedules for implementing these actions. For new forward-fit requirements, the imposition of a generic issue resolution is complete when the new requirement(s) becomes effective as an integral part of NRC regulations, policies, and/or guidance.

During the imposition stage, a resolved GSI is identified as a Multiplant Action (MPA) for licensee action. The imposition status of all MPAs is tracked in the Safety Issue Management System (SIMS).

Implementation

Implementation is the step in the generic issues program where the affected licensees perform the actions on existing plants to satisfy the commitments made during the imposition stage. These may include modifications/additions to equipment, structures, procedures, technical specifications, operating instructions, etc. No later than 30 days after each affected licensee has completed all of the actions required for a particular generic issue resolution, and the modified/additional system is fully operational, the licensee is required to certify in writing to the NRC that plant modifications have been completed in accordance with NRC requirements, policies, and/or guidance. When all affected licensees have officially notified the NRC of completion of all required/committed actions, the implementation stage is complete, unless it is determined by the staff from subsequent verification inspection that additional licensee actions are needed for compliance.

Verification

The verification step consists of three parts. First, the portions of a licensee's actions, if any, that warrant NRC inspection must be determined. This decision is made during the resolution stage based on the judgment of the safety significance of the issue relative to other matters in the inspection program, licensee performance, and the resources needed to accomplish a meaningful inspection. Next, as necessary, inspection instructions are prepared to ensure that the NRC inspection is performed in a consistent and appropriate manner at all affected plants; the inspection, by its very nature, is an audit. Therefore, carefully thought-out instructions must be provided to the NRC inspectors so that the maximum safety benefit is achieved for the limited resources devoted to this effort. The third part of the verification process is the actual verification and documentation of the results in an inspection report.

Physical inspections are performed on an audit basis in a manner consistent with general inspection procedures which involve a sampling of changes made by licensees or applicants, as opposed to a 100% inspection of all actions. Verification of licensee implementation of generic issue resolution is reported by the staff in SIMS.

III. PRIORITIZATION

Purpose and Scope

The primary purpose of prioritization is to assist in the timely and efficient allocation of resources to those safety issues that have a high potential for reducing risk and in decisions to remove from further consideration issues that have little safety significance and hold little promise of worthwhile safety enhancement. However, issues of such gravity that consideration of immediate action is called for are excluded from prioritization because of the compressed time scale in which decisions for such issues must be made.

Prioritization focuses on generic safety issues (GSIs) i.e., safety concerns that may affect the design, construction, or operation of all, several, or a class of nuclear power plants and may have the potential for safety improvements and promulgation of new or revised requirements or guidance. However, the method can be used to identify changes in current requirements that could significantly reduce the impact (usually cost) on licensees without any substantial change in public risk. Issues of this type are classified as Regulatory Impact issues (RI) to clearly differentiate them as not improving the safety of nuclear power plants but, nevertheless, possibly worthwhile.

In order to identify GSIs, all issues originated in accordance with OL #1[1192] are reviewed to determine their safety significance. Issues that primarily concern environmental protection or the licensing process and do not involve significant safety improvement elements are classified accordingly and noted for separate consideration outside the GSI priority ranking scheme. These issues are classified as either environmental issues or licensing issues. Environmental issues (EI) involve impacts on the human environment and the values sought to be protected by the National Environmental Policy Act (NEPA). Licensing issues (LI) are not directly related to protecting public health and safety or the environment, but relate to: (1) increasing the staff's knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety; (2) improving or maintaining the NRC capability to make independent assessments of safety; (3) establishing, revising, and carrying out programs to identify and resolve GSIs; (4) documenting, clarifying, or correcting current requirements and guidance; and (5) improving the effectiveness or efficiency of the review of applications.

The list of issues subjected to prioritization contains the following groups:

(1) TMI Action Plan items identified for development in NUREG-0660;[48] these issues are covered in Section 1. The priority recommendations

in this report exclude those issues that were designated for implementation in NUREG-0737.[98]

(2) Task Action Plan items identified in NUREG-0371[2] and NUREG-0471,[3] plus the subsequently added issues A-42 through A-49 that were designated as Unresolved Safety Issues (USIs); these issues are covered in Section 2. However, issues designated as USIs were excluded from prioritization because of the high-priority attention they were given based on priority decisions previously made. In the future, USIs will come from issues that have been prioritized.

(3) New Generic issues identified by the staff, ACRS, or others; these issues are covered in Section 3. All new issues identified will be prioritized and included in Section 3 and published in future supplements to this report.

(4) Human Factors Program Plan (HFPP) items identified for development in NUREG-0985;[603] these items are covered in Section 4.

(5) Chernobyl Issues identified in NUREG-1251;[1195] these issues are covered in Section 5.

A comprehensive listing of all issues in the above five groups is given in Table II which includes the following information for each issue: (1) the NRC person responsible for the prioritization evaluation; (2) the lead NRC office, division, and branch responsible for reviewing the prioritization analysis and/or resolving the issue; (3) the priority ranking or status; (4) the latest version of the evaluation; (5) the issuance date of the latest version of the evaluation; and (6) the MPA number for those issues that have been resolved and require licensee actions. A summary of the number of issues in each category is shown in Table III. A cross-reference listing of reports prepared by the Office for Analysis and Evaluation of Operational Data (AEOD) and their corresponding generic issues is provided in Table IV.

How the Work Is Done

The work is done, in accordance with the criteria described below, by the responsible NRC Branch in consultation with others in the NRC with knowledge of the issues or expertise in the technical disciplines involved. In a number of instances, technical or cost information is obtained from industry and other outside sources. The Battelle Pacific Northwest Laboratories (PNL), under a technical-assistance contract, developed detailed methods to quantify safety benefits and costs and provided safety-benefit analyses and cost information for many of the issues.[64] The responsible NRC Branch, with internal consultations as necessary, reviews and applies the PNL-supplied technical factors, in conjunction with additional factors, in developing the priority rankings and recommendations.

Systematic peer review of each prioritization evaluation within the NRC contributes to the assurance that the analysis is complete and accurate and that the judgments are soundly based. This review is done in two stages. First, each analysis is reviewed by the NRC organizational unit or units whose area of responsibility or specialized knowledge is substantially involved. Second, any comments made are then resolved, where practical, and factored into the analysis, as appropriate. Upon completion of peer review, the analysis is then finalized and prepared for approval by the responsible Office Director. Once approved, it is placed in the PDR and published in a future supplement to this report, after which, additional comments from the ACRS, the industry, and the public are considered in any further reassessment of the issue's priority.

Priority Categories: Their Meaning and Proposed Use

Four priority rankings are used: HIGH, MEDIUM, LOW, and DROP. They are intended for use in guiding allocation of NRC resources and scheduling of efforts to resolve the various issues, in conjunction with other pertinent factors such as: (1) the nature, extent, and availability of manpower and material resources estimated to be required; (2) length of time needed to resolve; (3) conflicts in resource allocation and scheduling among items of comparable priority; (4) status of affected reactors; and (5) budget constraints.

A HIGH priority ranking means that strong efforts to achieve the earliest practical resolution are appropriate. This is because: (a) an important safety concern may be involved (though generally the concern is not severe enough to require prompt plant shutdown); (b) a substantial safety improvement is likely to be attainable at a low enough cost to make the improvement worthwhile; or (c) the uncertainty of the safety assessment is unusually large and an upper-bound risk assessment would indicate an important safety concern. All unresolved HIGH priority issues are periodically reviewed in accordance with the criteria stated in NUREG-0705[44] for possible designation as USIs. A USI is defined as a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plants affected.[186] In accordance with Section 210 of the Energy Reorganization Act of 1974, progress on the resolution of USIs is reported to Congress in each NRC Annual Report.

A MEDIUM priority ranking means that no safety concern demanding high-priority attention is involved, but there is believed to be potential for safety improvements or reductions in uncertainty of analysis that may be substantial and worthwhile, though less so than for items assigned a HIGH priority. Efforts at resolution should be planned, perhaps over the ensuing years, but on a basis of not interfering with pursuit of HIGH-priority generic issues or other high-priority work.

A LOW priority ranking means that no safety concerns demanding at least MEDIUM-priority attention are involved and there is little or no prospect of safety improvements that are both substantial and worthwhile. When the prioritization process results in a LOW priority ranking for an issue, approval of this ranking by the responsible Office Director signifies that the issue has been eliminated from further pursuit.

The DROP category covers proposed issues that are without merit or whose significance is clearly negligible. Issues are also DROPPED from further consideration if it is determined that their safety concerns have been addressed in previously prioritized or resolved issues. When the prioritization process results in a DROP priority ranking for an issue, approval of this ranking by the responsible Office Director signifies that the issue has been eliminated from further pursuit.

An issue is considered resolved, indicated by NOTE 3 in Table II, when its resolution has resulted in the establishment of regulatory requirements or guidance (by Rule, SRP[11] change, or equivalent) or a documented authoritative decision that no change in requirements is warranted. Priority rankings are not assigned to issues that have been resolved. However, in those cases where issues were resolved after having been identified for further pursuit by the prioritization process, the related calculations have been retained in the text of this document for future use.

Priority rankings are not assigned to issues that are nearly-resolved (denoted by NOTES 1 and 2 in Table II) because approval of changes to requirements, based on the resolution of an issue, requires that a detailed value/impact evaluation of the safety benefit, implementation costs, and other relevant factors be made. Prioritization would duplicate this value/impact analysis, but in a less comprehensive manner. Therefore, the effort that would be needed to prioritize an issue is devoted to completing the final evaluation of the issue, rather than making a tentative judgment as to the importance and value of the issue. Possible resolution of an issue is considered to be identified, indicated by NOTE 1 in Table II, when a possible technical resolution is under evaluation and the evaluation is nearing completion. Further work may be required as part of the review and approval process before a change in requirements or guidance is issued. Resolution of an issue is considered available, indicated by NOTE 2 in Table II, when proposed or recommended changes to requirements or guidance are documented in a NUREG report, NRC memorandum, Safety Evaluation Report (SER), or equivalent.

Priority rankings are also not assigned to those issues whose safety concerns are determined to be covered (at the time of prioritization) in other issues of broader scope that are being prioritized or are being resolved. Issues in this category are integrated into the issues of broader scope. A detailed listing of all such issues is given in Table V.

Criteria For Assigning Priorities

1. Basic Approach

The method of assigning priority rank involves two primary elements: (i) the estimated safety importance of the issue; and (ii) the estimated cost of developing and implementing a resolution. Special considerations may influence the proper use of the estimates. These elements are applied as follows:

(a) The issue is identified and defined. Since issues are often complex and interrelated with other issues, careful definition of an issue's scope and bounds is essential in arriving at a sound and applicable assessment.

(b) A quantitative estimate is made of the safety importance of the issue, measured in terms of the risk (the product of accident probabilities and radiological consequences) attributable to the issue and the decrease in that risk that may be attainable by resolving the issue.

(c) A quantitative estimate is made of the cost of resolution.

(d) A numerical value/impact score is calculated by dividing the estimated potential risk reduction by the estimated cost entailed. This score denotes a value/impact relation, i.e., an estimated ratio of safety improvement value to cost impact.

(e) A priority rank (HIGH, MEDIUM, LOW, or DROP) is obtained by application of criteria in which both the safety significance of the issue and the value/impact-based numerical score are taken into account. The score is not always directly applied to determine the priority rankings. In some cases, the safety significance of the issue is so great that it demands a HIGH priority, or so minor that only a LOW priority (or a decision to DROP) is warranted irrespective of the value/impact assessment.

(f) The priority ranking is reviewed and modified, if appropriate, in light of any special factors (discussed below) that: (i) might bring into question the applicability of the necessarily simplified calculation technique; and (ii) call for special consideration of NRC management decisions or large uncertainties in the quantitative estimates.

In summary, while the method has a quantitative emphasis, the calculated numerical values are used as an aid to judgment and not as determinative of the ranking results. The nature of the specific issue, the quality of the data base, and the scope of the necessarily limited analysis determine in each case the dependability of the numerical indications as a judgment aid.

2. Safety Significance

The safety significance of an issue is represented by the reduction in risk that resolution could effect. Risk is ordinarily expressed here in terms of the product of the frequency of an accident occurrence and the public dose (in man-rem) that would result in the event of the accident. If more than one accident scenario is important within the necessarily rough risk estimates, the risks are summed.

The potential risk reduction calculated in this way is used in calculating the "value/impact score" as part of the simplified value/impact analysis, discussed in Paragraph III.3 below. It is also used directly as a measure of safety significance, as discussed in Paragraph III.4 below, in arriving at a priority rank that is influenced by the safety significance of an issue as well as by the estimated value/impact relation of a projected solution.

The man-rem-based risk reduction estimate may not be the only appropriate measure of an issue's safety significance in all cases. For example, when a possible core-melt is involved but release outside containment would be minor or highly improbable, contribution to the core-melt probability may well be more indicative of safety significance. Provision is made, as described in Paragraph III.4 below, for use of alternative measures of safety significance in determining a priority ranking when such alternative measures are useful.

3. Value/Impact Relation

a. The Value/Impact Score Formula

To the extent reasonably possible, quantitative estimates are made of the possible solutions to a GSI by calculating a "priority score" that reflects the relation between the risk reduction value expected to be achieved and the associated cost impact. The formula for the value/impact score (S) is:

$$S = \frac{\text{Safety Benefit}}{\text{Cost}}$$

where the safety benefit is the estimated risk reduction (event frequency x public dose averted) that may be achieved, and the cost is that thought necessary to develop and implement a resolution in the number of plants involved. The scoring computation for any issue is then:

$$S = \frac{NFTD}{C}$$

where N = number of reactors involved
T = average remaining life of the affected plants (years)
F = the accident frequency reduction (events/reactor-year)
D = public dose from the radioactive material released from containment (man-rem)
C = total cost of developing and implementing the resolution of the issue for all plants affected (millions of dollars).

The total cost (C) includes both the cost of developing the generic solution, which are typically NRC costs, and the cost of implementing the possible solution at all affected plants, which include design, equipment, installation, test, operation, and maintenance, and are typically industry costs. The priority score (S) has the units of man-rem per million dollars.

b. Rationale for the Formula

The qualitative diversity of factors entering value/impact analyses in support of GSI prioritization, together with inevitable quantitative uncertainties, make any of various possible value/impact score formulas necessarily imperfect.

Accordingly, provisions are made to compensate for those imperfections to the extent practical (as discussed in Paragraph III.5 below).

The formula selected measures a total-safety-benefit/total-cost relation. As discussed herein, it is applied within limits set by other possible considerations where a safety issue is either too important to depend on safety-cost tradeoffs or too trivial to merit attention at all. Two principal arguments favor a formula of this type:

(1) The numerator is designed as a direct measure of the safety values that it is NRC's primary mission to protect. The denominator is designed to measure the overall cost impact, including industry as well as NRC costs, and should thus reflect the entire public interest in economy. The resulting ratio (the value/impact score) should, subject to the stated caveats, reasonably approximate measuring the overall public interest in safety value received for total resources expended.

(2) The allocation of national resources, which in most cases are primarily industry resources, is optimized.

c. <u>Risk Estimates</u>

The risk estimates developed for GSIs are useful as rough approximations for comparative purposes, but are not necessarily applicable to the assessment of absolute levels of risk attributable to particular issues. Similarly, the value/impact scores provide, for the limited purpose of prioritization, tentative assessments of relative potential for cost-effective resolution. They are not intended to be applied as value/impact determinations for any regulatory proposal that may ultimately result from efforts to resolve an issue. In addition, the assumed resolutions are not intended to prejudge the final resolutions, but are only assumptions that are necessary to perform quantitative analyses.

The basis of frequency estimates generally involves the following:

(1) Identification of the specific events which are the basis for the concern, for which the consequences are to be established, and which are to be eliminated or ameliorated by a proposed technical solution

(2) Use of event sequence diagrams, fault trees, or decision trees, if possible

(3) Identified references and calculations, or stated assumptions for the numbers used

(4) Consideration of the probability of common mode as well as random independent failures.

Exhibit B

Release Category	Release (Curies)	Estimated Public Dose (man-rem)
PWR-1	1.2×10^9	5,400,000
PWR-2	9.3×10^8	4,800,000
PWR-3	5.2×10^8	5,400,000
PWR-4	2.8×10^8	2,700,000
PWR-5	1.3×10^8	1,000,000
PWR-6	1.0×10^8	150,000
PWR-7	2.1×10^6	2,300
PWR-8*	7.7×10^5	75,000
PWR-9*	1.1×10^3	120
BWR-1	1.1×10^9	5,400,000
BWR-2	1.1×10^9	7,100,000
BWR-3	5.0×10^8	5,100,000
BWR-4	2.1×10^8	610,000
BWR-5*	1.7×10^5	20

* Non-core-melt (Other release categories involve core-melt).

Where possible, numerical estimates are made based on operating experience, usually Licensee Event Reports (LERs). Other sources include prior PRAs and other risk and reliability studies. Some numbers are based on engineering judgment; in such cases, the basis for that judgment is stated.

For the identified end event(s), the expected radiological consequences are expressed in man-rem generally based on the radioactive release categories described in WASH 1400[16] (Appendix VI, pp. 2-1 to 2-5), reproduced as Appendix A to this report. Exhibit B gives estimated Curies released and approximate population doses for each release category. The computer program CRAC2, applied to a typical midwest site (Braidwood) meteorology, was used for the dose calculations. However, the calculated doses were adjusted to reflect the mean of the population density within a 50-mile radius of U.S. nuclear power plants.[64] Assumptions and parameters used for the calculations were as follows:

- Consequences are represented by the whole body population dose (man-rem) received within 50 miles of the site.

- An exclusion area of 1/2 mile was assumed with a uniform population density of 340 persons per square mile beyond 1/2 mile. This is the mean 50-mile radius population density projected for the year 2000 (NUREG-0348, p. T52).[70]

- Evacuation of people was not considered because of the possible large variations in evacuation capability for each plant site.

- All exposure pathways were included in the basis of the tabulated numbers except ingestion pathways, i.e., interdiction of contaminated foods was assumed. (Farmland usage parameters for the State of Illinois were used for separate ingestion pathway calculations where made.)

- Meteorological data was taken from the U.S. National Weather Service station at Moline, Illinois.

The man-rem factors for each release category are given in Exhibit B. Although generally used, consequence estimates were not solely based on these factors. Other factors were used in some cases when more appropriate.

An estimated occupational dose of 20,000 man-rem from postaccident cleanup, repair, and refurbishment is also considered.

Where significant occupational radiological exposure (ORE) is incurred or averted in implementing current requirements or the proposed resolution of a GSI, such exposure is taken into account but stated separately. Where more direct issue-specific ORE information is lacking, dose estimates are obtained by assuming an average dose rate of 2.5 millirem/hour (based on the PNL analysis[64] cited above) and multiplying by the estimated number of man-hours involved.

A second factor is that the risk associated with an issue is more likely to be overestimated than underestimated. Where risk estimates are widely uncertain, a reasonably conservative value of risk reduction is generally selected to help assure adequate priority to issues that may warrant attention.

The sum of the estimated risks of all the separate issues will likely exceed the present estimate of the total risk of nuclear power plants because of two factors. First, individual accident sequences can be affected by more than one issue. The resolution of one issue would reduce the probability or consequences of a certain set of accident sequences. Some or even all of these sequences could be the same as some or even all of the sequences affected by another issue. However, issues are assessed independently and this interaction is not considered. This interaction is strongest for issues related to human factors, since human error affects almost all sequences. The sum of the reductions in core-melt frequency estimated for all of the human factors-related issues may be as much as twice as great as the total human factors contribution to total risk. However, most of the issues not related to human factors are much less strongly interrelated.

d. Cost Estimates

Because cost estimates are used here only in relation to risk estimates which are generally subject to more or less wide uncertainties, only approximate costs are needed.

No separate estimates are generally made for offsite property damage; reasonably conservative use of the public dose estimates is an adequate surrogate in this application. Furthermore, there is no readily-available data on offsite damage that is realistic and detailed enough to make estimates meaningful, reasonably accurate, and generically applicable. If unusual or special offsite effects are not adequately represented by the public dose in some issues, this fact will be considered separately and explicitly in evaluating such issues.

The expected technical solution on which the cost estimate is based is identified. Estimated costs are established by collecting available data regarding engineering, procurement, installation, testing, and periodic inspection and maintenance. Where data are non-existent, estimates are based on judgments by the experts involved. Assumptions and estimated uncertainties are identified. Costs are estimated in 1982 dollars.

NRC costs include the following: (1) issue identification, analysis, resolution, and report issuance; (2) research to establish proposed specific changes to licensing requirements (or to determine that no change is required); (3) technical assistance contracts (including associated NRC effort); (4) discussions and correspondence with industry owners' groups; (5) plant reviews; and (6) preparation and review of SERs and requirement documents. The estimated cost of NRC professional time is based on $100,000 per person-year.

The costs to industry generally consist of some combination of the following: (1) licensing; (2) design; (3) equipment procurement; (4) installation; (5) testing, inspection, monitoring, and periodic maintenance; and (6) plant downtime to effect a change, taken as the cost of replacement power at $300,000/day. Industry manpower costs are taken as $100,000 per person-year.

In some cases, averted plant damage costs may affect the priority of a GSI. Estimates for such averted costs are developed and used in separately stated calculations so that the priority scores, both with and without adjustment for averted plant damage costs, are readily apparent. The averted costs may include those of averted equipment failures, limited-time plant outage, or limited plant-contamination cleanup. In the extreme, they can also include averted permanent loss of use of the plant, estimated at approximately $1 billion present worth, and plant-wide cleanup, estimated (on a basis consistent with TMI estimates[393]) at a present worth of about $400 million, both based on a 5% real discount rate and multiplied in each case by the reduction in frequency of such events that would be brought about by resolution of the GSI. The plant loss estimate includes allowance for typical plant age at the time of the accident as well as replacement power costs together with apportioned cost of a replacement plant. The plant-wide cleanup estimate reflects cleanup to the point at which the plant is ready for decommissioning or refurbishing for restart. Thus, for complete plant loss, the $1 billion and $400 million are added. Refurbishing costs, when restart is more economical than decommissioning, would depend on the nature of the accident and could range from a fraction of the total plant loss figure to a cost approaching that figure.

Some fixed costs are one-time, initial costs; others may occur at future times. Future costs are discounted to present worth at a 5% rate. Where costs are continuous or periodically recurring throughout a plant's remaining life, the periodic cost is taken into account using an approximation of the present worth of the continuing (or repetitive) costs for plants with remaining operating lives of 20 years or longer.

e. Uncertainty Bounds

Major sources of uncertainty in the priority score are identified and judgments as to their quantitative significance are indicated as information warrants. Where data warrant, the method described in NUREG/CR-2800,[64] Section 5, for the general case of combining uncertainties for random variables with unknown distributions (as well as some special cases) are used. [See also Paragraph III.5(a)]. Most often, however, a rigorous uncertainty analysis is not warranted. In most cases, the uncertainty in the point estimates of risks and costs is known to be large. However, sufficient information is not usually available to make a meaningful quantitative analysis of the uncertainty bounds of these point estimates. Decisions are tempered by the knowledge that the uncertainty is generally large. This knowledge was also used in developing the chart of tentative priority rankings (Figure 1). The wide spread between a level of risk, for example, at which an issue would be ranked as having a high priority and the level at which an issue would be ranked as low priority (a factor of 100) is partially based on the recognition that the uncertainties are large. In cases where uncertainty has a special character or importance, this is discussed and considered in the conclusion of the analysis of the GSI.

4. Priority Ranking

(a) Priority Ranking Chart

A chart showing how the tentative priority rankings are derived from the safety significance of an issue and its value/impact priority score is presented in Figure 1. The thresholds on the chart are discussed in Paragraphs III.4(b) and III.4(c) below.

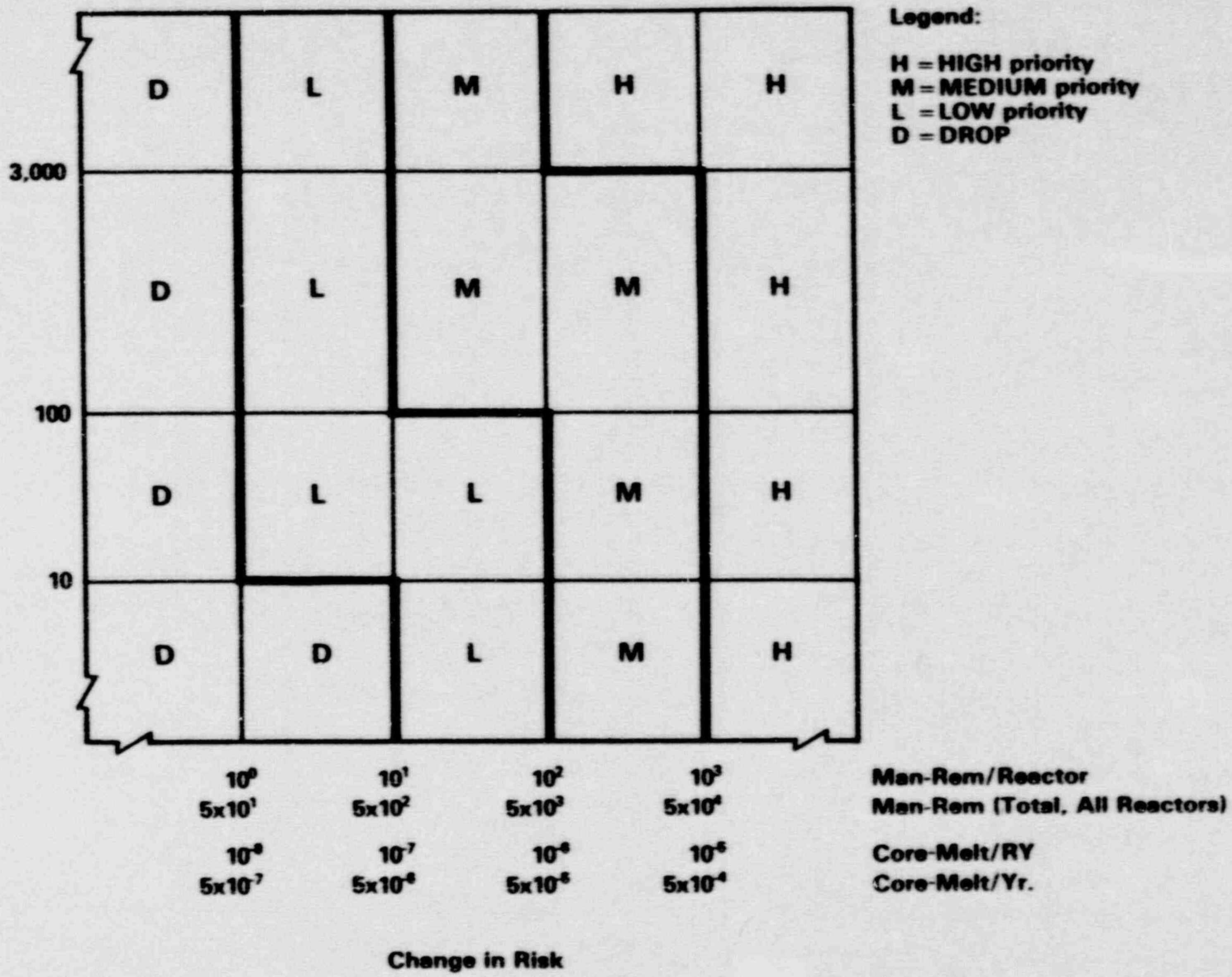

Figure 1-Priority Ranking

(b) Preliminary Screening for Safety Significance

The value/impact-based priority score is applied after a preliminary screening on the basis of safety significance, i.e., the incremental risk associated with the issue. The safety significance of an issue may be such that it should be accorded a HIGH priority regardless of other considerations, such as an initially estimated high cost, which might result in a low priority score. When a GSI is considered important from the safety viewpoint, the assignment of a HIGH priority to its resolution should not be deterred by the initial absence of an identified solution that could be implemented with a moderate cost.

At the other extreme, an issue's safety significance could be too minor to warrant diversion of attention from more important safety issues even if it has a high priority score because an inexpensive solution is believed to be available. Below a minimal safety significance threshold, the priority would always be DROP; where the potential risk reduction is trivial, there can be no basis for regulatory action on safety grounds.

In between, there may be issues of less extreme importance or unimportance that demand at least a MEDIUM (or at least a LOW) priority or warrant at most a MEDIUM (or at most a LOW) priority.

The risk-based priority ranking thresholds are shown in Table I. Thresholds a(2) and a(4) in Table I reflect the view that an issue affecting a large number of reactors may warrant as high a priority as an issue that involves somewhat greater per-reactor risk but affects only a few reactors.

(c) Value/Impact Score Thresholds

To the extent consistent with the safety significance screening criteria discussed above, the value/impact priority score (S) is translated into priority rankings in accordance with the following thresholds:

(1) If at least 3,000 man-rem/$million, an issue that is above 10% of the HIGH risk threshold would warrant a HIGH priority rather than a MEDIUM priority.

(2) If less than 100 man-rem/$million, an issue that is below 10% of the HIGH risk threshold would only warrant a LOW priority rather than a MEDIUM priority.

(3) If less than 10 man-rem/$million, an issue that is below 1% of the HIGH risk threshold would only warrant a DROP priority rather than a LOW priority.

TABLE I

RISK THRESHOLDS

(a) The priority rank is always HIGH when any of the following risk (or risk-related) thresholds are estimated to be exceeded (or when extraordinary uncertainty suggests that they may well be exceeded):

(1) 1,000 man-rem estimated public dose per remaining reactor lifetime

(2) 50,000 man-rem total estimated for all affected reactors for their remaining lifetime (e.g., 500 man-rem/reactor for 100 reactors)

(3) 10^{-5}/reactor-year large-scale core-melt

(4) 5×10^{-4}/year large-scale core-melt (total for all affected reactors)

(b) Always at least MEDIUM priority:
10 or more percent of the always-HIGH criteria

(c) Always at least LOW priority:
1 or more percent of the always-HIGH criteria

(d) Never higher than MEDIUM priority:
Less than 10% of the always-HIGH criteria

(e) Never higher than LOW priority:
Less than 1% of the always-HIGH criteria

(f) Always DROP category:
Less than 0.1% of the always-HIGH criteria

5. Other Considerations

The formula-based rankings represent the primary concern of the NRC: public safety. The secondary concern is the impact on licensees, evaluated in terms of cost. However, the tentative priority rankings are subject to the limitations of an often incomplete and imprecise data base and to possible distortions due to the nature of the necessarily highly simplified quantitative formula under-lying them. (This is the principal reason for establishing low threshold values for the LOW and DROP categories.) Special situations with respect to some issues may cause added difficulty in priority assignment. While the formula-based tentative rankings must generally indicate that the safety significance is sufficient to justify NRC action, other considerations not adequately reflected, or not reflected at all, in the numerical formula are often needed to corroborate or adjust the results. Decision-making is helped by explicit identification of such other considerations and explanation of how they bear on the resulting final priority ranking, whether the effect is one of corroborating or of changing the estimates. Listed below are some factors that may be important in arriving at a sound priority ranking and may lead to adjustment of a tentative, formula-derived ranking. Possible effects of occupational doses, averted plant-damage costs, and uncertainty bounds [(a)(1), (a)(2), (a)(3), and (b)(1) below] require particularly careful consideration for all issues. The factors listed are not considered all inclusive. Others thought significant are discussed and, when practical, quantified appropriately in the overall priority score and its associated uncertainties. Sometimes, there are special considerations that are quite specific to an issue or some aspect of it. The partial list of other factors is listed below.

(a) Special risk and cost aspects not included in or potentially masked by the numerical formulas:

  (1) The net change in occupational doses implicit in implementing the current versus the proposed requirements; also, non-radiological occupational hazards inherent in, or affected by, the proposed resolutions.

  (2) Any significant non-radiation-related occupational risk.

  (3) Averted cost of plant damage from the postulated accident.

  (4) Loss or severe degradation of a layer in the defense-in-depth concept (e.g., one mode of core cooling or containment cooling).

  (5) Issues for which solutions of widely differing costs may be applicable to different classes of plants or various plants are otherwise affected in vastly different ways.

(b) Factors related to uncertainties stemming from an incomplete or imprecise data base for the priority formula:

(1) Uncertainty bounds, imbalance in uncertainty factors, certainty of cost to fix versus uncertainty that safety is really improved and the true extent of such improvement.

(2) Situations where uncertainty is extraordinarily large (in accident probability, consequences, or cost, or any or all of these).

(3) Problems which are ill-defined and problems for which solutions are not evident so that at least the resources necessary to understand the problem are assigned

(4) The potential for a proposed change to affect more than one accident or transient sequence, thus affecting risk to a greater or lesser degree than assessed in the description of the issue; notably, the potential for a new safety decrement, or increase in risk, due to unidentified effects of a proposed change, or added complexity, or for other reasons

(5) Circumstances imparting unusual significance to accident consequences (such as ingestion-pathway effects) or mitigating measures (such as evacuation) that are not directly included in the public dose calculations

(6) Potential for human intervention, using available equipment.

(c) Perceptions and judgments that cannot (or cannot readily) be quantified:

(1) Public concern about a particular issue, or special Commission or Congressional concern

(2) Acute knowledgeable professional controversy concerning the importance of an issue or modes of dealing with it.

(d) Change with passage of time:

(1) Potential substantial deterioration of the value/impact ratio while awaiting regulatory resolution (e.g., a potential design fix that is inexpensive to apply before construction, much more expensive after the plant is largely built, and extremely expensive and problematical to apply to an operating plant)

(2) The amount of resources already spent on an issue, and how close to completion it may be; the value of continuity in efforts to resolve an issue

(3) The span of time predicted to resolve an issue and implement the resolution

(4) The clarity of an "issue" and the objectivity with which it is currently defined (perhaps additional research effort is necessary to identify and define a specific risk reduction of interest)

(5) Change of perceptions (of safety importance or value/impact relation or some special issue-peculiar factor) in the course of time.

Generally, in situations of large doubt or conflicting indications, the highest priority rank reasonably consistent with the nature of an issue is assigned. Thus, where no solution is evident, assignment of a priority consistent with the safety significance of the issue may lead to a search for resolution or mitigation at an acceptable cost. Generally, should uncertainties narrow or perceptions change in the course of time, the priority rankings can be reexamined in the light of new developments and retained or changed. When different classes of plants are expected to be very differently affected by a potential resolution, the priority assignment is governed by the class of plants for which resolution is most worthwhile and urgent. (Resolution in such cases can involve a new requirement for some class of plants and no action for others.) Where resolution differs for different classes of plants, differing priorities may be assigned.

6. Concluding Remarks

The criteria and estimating process on which the priority rankings are based are neither rigorous nor precise. Considerable application of professional judgment, sometimes guided by good information but often tenuously based, occurs at a number of stages in the process when numerical values are selected for use in the formula calculations and when other considerations are taken into account in corroborating or changing a priority ranking. What is important in the process is that it is systematic, that it is guided by analyses that are as quantitative as the situation reasonably permits, and that the bases and rationale are explicitly stated, providing a "visible" information base for decision. The impact of imprecision is blunted by the fact that only approximate rankings (in only four broad priority categories) are necessary and sought.

IV. RESULTS OF PRIORITIZATION

The results of the prioritization and resolution of all issues contained in this report are summarized and tabulated by group in Table III. In addition, a listing of those issues that affect operating and future plants is given in Appendix B. This appendix reflects the results of prioritization and resolution and only includes: (1) issues that have been resolved with new requirements [NOTE 3(a)]; (2) USI, HIGH and MEDIUM priority issues that are being resolved; (3) nearly-resolved issues (NOTES 1 and 2); and (4) issues that are scheduled for prioritization and whose impact is not yet known (NOTE 4).

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1. SECY-81-513, "Plan for Early Resolution of Safety Issues," August 25, 1981.

2. NUREG-0371, "Task Action Plans for Generic Activities (Category A)," U.S. Nuclear Regulatory Commission, November 1978.

3. NUREG-0471, "Generic Task Problem Descriptions (Categories B, C, and D)," U.S. Nuclear Regulatory Commission, June 1978.

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

16. WASH-1400 (NUREG-75/014), "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," U.S. Nuclear Regulatory Commission, October 1975.

44. NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plant Stations," U.S. Nuclear Regulatory Commission, March 1981.

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983.

70. NUREG-0348, "Demographic Statistics Pertaining to Nuclear Power Reactor Sites," U.S. Nuclear Regulatory Commission, November 1979.

98. NUREG-0737, "Clarification of TMI Action Plan Requirements," U.S. Nuclear Regulatory Commission, November 1980.

186. NUREG-0510, "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants," U.S. Nuclear Regulatory Commission, January 1979.

197. Code of Federal Regulations, Title 10, Energy.

210. NUREG-0885, Issue 2, "U.S. Nuclear Regulatory Commission Policy and Planning Guidance," U.S. Nuclear Regulatory Commission, January 1983.

387. NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," U.S. Nuclear Regulatory Commission, January 1978.

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1189. Memorandum for W. Dircks from S. Chilk, "SECY-83-221 - Prioritization of Generic Safety Issues," December 9, 1983.

1190. Federal Register Notice 43 FR 1565, "Program for Resolution of Generic Issues Related to Nuclear Power Plants," January 10, 1978.

1191. Federal Register Notice 54 FR 24432, "Program for Resolution of Generic Issues Related to Nuclear Power Plants; Policy Statement," June 7, 1989.

1192. Memorandum for R. Fraley, et al., from E. Beckjord, "RES Office Letter No. 1, 'Procedure for Identification, Prioritization, and Tracking of the Resolution of Generic Issues,'" December 3, 1987, (Rev. 1) March 22, 1989.

1193. Memorandum for R. Fraley, et al., from E. Beckjord, "RES Office Letter No.2, 'Procedures for Obtaining Regulatory Impact Analysis Review and Support,'" November 18,1988.

1194. Memorandum for R. Fraley et al., from E. Beckjord, "RES Office Letter No.3 Procedure and Guidance for the Resolution of Generic Issues," May 10, 1988, (Rev. 1) December 21, 1988, (Rev. 2) March 27, 1989.

1195. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commerical Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Vol. 1) April 1989, (Vol. 2) April 1989.

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TABLE II

LISTING OF ALL TMI ACTION PLAN ITEMS, TASK ACTION PLAN ITEMS, NEW GENERIC ISSUES, AND HUMAN FACTORS ISSUES

This table contains the priority designations for all issues listed in this report. For those issues found to be covered in other issues, the appropriate notations have been made in the Safety Priority Ranking column, e.g., I.A.2.2 in the Safety Priority Ranking column means that Item I.A.2.6(3) is covered in Item I.A.2.2. For resolved issues that have resulted in new requirements for operating plants, the appropriate multiplant licensing action number is listed. The licensing action numbering system bears no relationship to the numbering systems used for identifying the prioritized issues. An explanation of the classification and status of the issues is provided in the legend below.

Legend

NOTES:
1 - Possible Resolution Identified for Evaluation
2 - Resolution Available (Documented in NUREG, NRC Memorandum, SER, or equivalent)
3 - Resolution Resulted in either: (a) The Establishment of New Regulatory Requirements (By Rule, SRP Change, or equivalent)
or (b) No New Requirements
4 - Issue to be Prioritized in the Future
5 - Issue that is not a Generic Safety Issue but should be Assigned Resources for Completion

HIGH	- High Safety Priority
MEDIUM	- Medium Safety Priority
LOW	- Low Safety Priority
DROP	- Issue Dropped as a Generic Issue
EI	- Environmental Issue
I	- Resolved TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737[98]
LI	- Licensing Issue
MPA	- Multiplant Action
NA	- Not Applicable
RI	- Regulatory Impact Issue
USI	- Unresolved Safety Issue

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
	TMI ACTION PLAN ITEMS						
I.A	OPERATING PERSONNEL						
I.A.1	Operating Personnel and Staffing						
I.A.1.1	Shift Technical Advisor	-	NRR/DHFS/LQB	I	2	12/31/86	F-01
I.A.1.2	Shift Supervisor Administrative Duties	-	NRR/DHFS/LQB	I	2	12/31/86	
I.A.1.3	Shift Manning	-	NRR/DHFS/LQB	I	2	12/31/86	F-02
I.A.1.4	Long-Term Upgrading	Colmar	RES/DFO/HFBR	NOTE 3(a)	2	12/31/86	
I.A.2	Training and Qualifications of Operating Personnel						
I.A.2.1	Immediate Upgrading of Operator and Senior Operator Training and Qualifications	-	-	-			
I.A.2.1(1)	Qualifications - Experience	-	NRR/DHFS/LQB	I	5	12/31/87	F-03
I.A.2.1(2)	Training	-	NRR/DHFS/LQB	I	5	12/31/87	F-03
I.A.2.1(3)	Facility Certification of Competence and Fitness of Applicants for Operator and Senior Operator Licenses	-	NRR/DHFS/LQB	I	5	12/31/87	F-03
I.A.2.2	Training and Qualifications of Operations Personnel	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.3	Administration of Training Programs	-	NRR/DHFS/LQB	I	5	12/31/87	
I.A.2.4	NRR Participation in Inspector Training	Colmar	NRR/DHFS/LQB	LI (NOTE 3)	5	12/31/87	NA
I.A.2.5	Plant Drills	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6	Long-Term Upgrading of Training and Qualifications	-	-	-			
I.A.2.6(1)	Revise Regulatory Guide 1.8	Colmar	NRR/DHFT/HFIB	NOTE 3(a)	5	12/31/87	NA
I.A.2.6(2)	Staff Review of NRR 80-117	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6(3)	Revise 10 CFR 55	Colmar	NRR/DHFS/LQB	I.A.2.2	5	12/31/87	NA
I.A.2.6(4)	Operator Workshops	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6(5)	Develop Inspection Procedures for Training Program	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6(6)	Nuclear Power Fundamentals	Colmar	NRR/DHFS/LQB	DROP	5	12/31/87	NA
I.A.2.7	Accreditation of Training Institutions	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.3	Licensing and Requalification of Operating Personnel						
I.A.3.1	Revise Scope of Criteria for Licensing Examinations	Emrit	NRR/DHFS/LQB	I	5	12/31/86	
I.A.3.2	Operator Licensing Program Changes	Emrit	NRR/DHFS/OLB	NOTE 3(b)	5	12/31/86	NA
I.A.3.3	Requirements for Operator Fitness	Colmar	RES/DRAO/HFSB	NOTE 3(b)	5	12/31/86	NA
I.A.3.4	Licensing of Additional Operations Personnel	Thatcher	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/86	NA
I.A.3.5	Establish Statement of Understanding with INPO and DOE	Thatcher	NRR/DHFS/HFEB	LI (NOTE 3)	5	12/31/86	NA
I.A.4	Simulator Use and Development						
I.A.4.1	Initial Simulator Improvement	-	-	-			
I.A.4.1(1)	Short-Term Study of Training Simulators	Thatcher	NRR/DHFS/OLB	NOTE 3(b)	5	06/30/88	NA
I.A.4.1(2)	Interim Changes in Training Simulators	Thatcher	NRR/DHFS/OLB	NOTE 3(a)	5	06/30/88	
I.A.4.2	Long-Term Training Simulator Upgrade	-	-	-			
I.A.4.2(1)	Research on Training Simulators	Colmar	NRR/DHFT/HFIB	NOTE 3(a)	5	06/30/88	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
I.A.4.2(2)	Upgrade Training Simulator Standards	Colmar	RES/DFO/HFBR	NOTE 3(a)	5	06/30/88	
I.A.4.2(3)	Regulatory Guide on Training Simulators	Colmar	RES/DFO/HFBR	NOTE 3(a)	5	06/30/88	
I.A.4.2(4)	Review Simulators for Conformance to Criteria	Colmar	NRR/DLPQ/LOLB	NOTE 3(a)	5	06/30/88	
I.A.4.3	Feasibility Study of Procurement of NRC Training Simulator	Colmar	RES/DAE/RSRB	LI (NOTE 3)	5	06/30/88	NA
I.A.4.4	Feasibility Study of NRC Engineering Computer	Colmar	RES/DAE/RSRB	LI (NOTE 3)	5	06/30/88	NA
I.B.	SUPPORT PERSONNEL						
I.B.1	Management for Operations						
I.B.1.1	Organization and Management Long-Term Improvements	-	-	-			
I.B.1.1(1)	Prepare Draft Criteria	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(2)	Prepare Commission Paper	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(3)	Issue Requirements for the Upgrading of Management and Technical Resources	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(4)	Review Responses to Determine Acceptability	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(5)	Review Implementation of the Upgrading Activities	Colmar	OIE/DQASIP/ORPB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(6)	Prepare Revisions to Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	I.A.2.6(1), 75	3	12/31/86	NA
I.B.1.1(7)	Issue Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	I.A.2.6(1), 75	3	12/31/86	NA
I.B.1.2	Evaluation of Organization and Management Improvements of Near-Term Operating License Applicants	-	-	-			
I.B.1.2(1)	Prepare Draft Criteria	-	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/86	NA
I.B.1.2(2)	Review Near-Term Operating License Facilities	-	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/86	NA
I.B.1.2(3)	Include Findings in the SER for Each Near-Term Operating License Facility	-	NRR/DL/ORAB	NOTE 3(b)	3	12/13/86	NA
I.B.1.3	Loss of Safety Function	-	-	-			
I.B.1.3(1)	Require Licensees to Place Plant in Safest Shutdown Cooling Following a Loss of Safety Function Due to Personnel Error	Sege	RES	LI (NOTE 3)	3	12/31/86	NA
I.B.1.3(2)	Use Existing Enforcement Options to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	3	12/31/86	NA
I.B.1.3(3)	Use Non-Fiscal Approaches to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	3	12/31/86	NA
I.B.2	Inspection of Operating Reactors						
I.B.2.1	Revise OIE Inspection Program	-	-	-			
I.B.2.1(1)	Verify the Adequacy of Management and Procedural Controls and Staff Discipline	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(2)	Verify that Systems Required to Be Operable Are Properly Aligned	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
I.B.2.1(3)	Follow-up on Completed Maintenance Work Orders to Assure Proper Testing and Return to Service	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(4)	Observe Surveillance Tests to Determine Whether Test Instruments Are Properly Calibrated	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(5)	Verify that Licensees Are Complying with Technical Specifications	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(6)	Observe Routine Maintenance	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(7)	Inspect Terminal Boards, Panels, and Instrument Racks for Unauthorized Jumpers and Bypasses	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.2	Resident Inspector at Operating Reactors	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)		11/30/83	NA
I.B.2.3	Regional Evaluations	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)		11/30/83	NA
I.B.2.4	Overview of Licensee Performance	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)		11/30/83	NA
<u>I.C</u>	<u>OPERATING PROCEDURES</u>						
I.C.1	Short-Term Accident Analysis and Procedures Revision	-	-	-			
I.C.1(1)	Small Break LOCAs	-	NRR	I	3	12/31/86	
I.C.1(2)	Inadequate Core Cooling	-	NRR	I	3	12/31/86	F-04
I.C.1(3)	Transients and Accidents	-	NRR	I	3	12/31/86	F-05
I.C.1(4)	Confirmatory Analyses of Selected Transients	Riggs	NRR/DSI/RSB	NOTE 3(b)	3	12/31/86	NA
I.C.2	Shift and Relief Turnover Procedures	-	NRR	I	3	12/31/86	
I.C.3	Shift Supervisor Responsibilities	-	NRR	I	3	12/31/86	
I.C.4	Control Room Access	-	NRR	I	3	12/31/86	
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	-	NRR/DL	I	3	12/31/86	F-06
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	-	NRR/DL	I	3	12/31/86	F-07
I.C.7	NSSS Vendor Review of Procedures	-	NRR/DHFS/PSRB	I	3	12/31/86	
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	-	NRR/DHFS/PSRB	I	3	12/31/86	
I.C.9	Long-Term Program Plan for Upgrading of Procedures	Riggs	NRR/DHFS/PSRB	NOTE 3(b)	3	12/31/86	NA
<u>I.D</u>	<u>CONTROL ROOM DESIGN</u>						
I.D.1	Control Room Design Reviews	-	NRR/DL	I	4	06/30/88	F-08
I.D.2	Plant Safety Parameter Display Console	-	NRR/DL	I	4	06/30/88	F-09
I.D.3	Safety System Status Monitoring	Thatcher	RES/DE/MEB	MEDIUM	4	06/30/88	
I.D.4	Control Room Design Standard	Thatcher	RES/DRPS/RHFB	NOTE 3(b)	4	06/30/88	NA
I.D.5	Improved Control Room Instrumentation Research	-	-	-			
I.D.5(1)	Operator-Process Communication	Thatcher	RES/DFO/HFBR	NOTE 3(b)	4	06/30/88	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
I.D.5(2)	Plant Status and Post-Accident Monitoring	Thatcher	RES/DFO/HFBR	NOTE 3(a)	4	06/30/88	
I.D.5(3)	On-Line Reactor Surveillance System	Thatcher	RES/DE/MEB	NOTE 1	4	06/30/88	
I.D.5(4)	Process Monitoring Instrumentation	Thatcher	RES/DFO/ICBR	NOTE 3(b)	4	06/30/88	NA
I.D.5(5)	Disturbance Analysis Systems	Thatcher	RES/DRPS/RHFB	LI (NOTE 5)	4	06/30/88	NA
I.D.6	Technology Transfer Conference	Thatcher	RES/DFO/HFBR	LI (NOTE 3)	4	06/30/88	NA
I.E	ANALYSIS AND DISSEMINATION OF OPERATING EXPERIENCE						
I.E.1	Office for Analysis and Evaluation of Operational Data	Matthews	AEOD/PTB	LI (NOTE 3)	1	6/30/84	NA
I.E.2	Program Office Operational Data Evaluation	Matthews	NRR/DL/ORAB	LI (NOTE 3)	1	6/30/84	NA
I.E.3	Operational Safety Data Analysis	Matthews	RES/DRA/RRBR	LI (NOTE 3)	1	6/30/84	NA
I.E.4	Coordination of Licensee, Industry, and Regulatory Programs	Matthews	AEOD/PTB	LI (NOTE 3)	1	6/30/84	NA
I.E.5	Nuclear Plant Reliability Data System	Matthews	AEOD/PTB	LI (NOTE 3)	1	6/30/84	NA
I.E.6	Reporting Requirements	Matthews	AEOD/PTB	LI (NOTE 3)	1	6/30/84	NA
I.E.7	Foreign Sources	Matthews	IP	LI (NOTE 3)	1	6/30/84	NA
I.E.8	Human Error Rate Analysis	Matthews	RES/DFO/HFBR	LI (NOTE 3)	1	6/30/84	NA
I.F	QUALITY ASSURANCE						
I.F.1	Expand QA List	Pittman	RES/DRA/ARGIB	NOTE 3(b)	2	06/30/89	NA
I.F.2	Develop More Detailed QA Criteria	-	-	-			
I.F.2(1)	Assure the Independence of the Organization Performing the Checking Function	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(4)	Establish Criteria for Determining QA Requirements for Specific Classes of Equipment	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(5)	Establish Qualification Requirements for QA and QC Personnel	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(6)	Increase the Size of Licensees' QA Staff	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(7)	Clarify that the QA Program Is a Condition of the Construction Permit and Operating License	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(8)	Compare NRC QA Requirements with Those of Other Agencies	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(10)	Clarify Requirements for Maintenance of "As-Built" Documentation	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(11)	Define Role of QA in Design and Analysis Activities	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
I.G	PREOPERATIONAL AND LOW-POWER TESTING						
I.G.1	Training Requirements	-	NRR/DHFS/PSRB	I	2	06/30/89	
I.G.2	Scope of Test Program	V'Molen	NRR/DHFS/PSRB	NOTE 3(a)	2	06/30/89	NA
II.A	SITING						
II.A.1	Siting Policy Reformulation	V'Molen	NRR/DE/SAB	NOTE 3(b)	1	12/31/84	NA
II.A.2	Site Evaluation of Existing Facilities	V'Molen	NRR/DE/SAB	V.A.1	1	12/31/84	NA
II.B	CONSIDERATION OF DEGRADED OR MELTED CORES IN SAFETY REVIEW						
II.B.1	Reactor Coolant System Vents	-	NRR/DL	I	2	06/30/88	F-10
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	-	NRR/DL	I	2	06/30/88	F-11
II.B.3	Post-Accident Sampling	-	NRR/DL	I	2	06/30/88	F-12
II.B.4	Training for Mitigating Core Damage	-	NRR/DL	I	2	06/30/88	F-13
II.B.5	Research on Phenomena Associated with Core Degradation and Fuel Melting	-	-	-			
II.B.5(1)	Behavior of Severely Damaged Fuel	V'Molen	RES/DRAA/AEB	LI (NOTE 5)	2	06/30/88	NA
II.B.5(2)	Behavior of Core Melt	V'Molen	RES/DRAA/PRAB	LI (NOTE 5)	2	06/30/88	NA
II.B.5(3)	Effect of Hydrogen Burning and Explosions on Containment Structure	V'Molen	RES/DRAA/AEB	LI (NOTE 5)	2	06/30/88	NA
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	Pittman	NRR/DST/RRAB	NOTE 3(a)	2	06/30/88	
II.B.7	Analysis of Hydrogen Control	Matthews	NRR/DSI/CSB	II.B.8	2	06/30/88	
II.B.8	Rulemaking Proceeding on Degraded Core Accidents	V'Molen	RES/DRAO/RAMR	NOTE 3(a)	2	06/30/88	
II.C	RELIABILITY ENGINEERING AND RISK ASSESSMENT						
II.C.1	Interim Reliability Evaluation Program	Pittman	RES/DRAO/RRB	NOTE 3(b)	2	12/31/88	NA
II.C.2	Continuation of Interim Reliability Evaluation Program	Pittman	NRR/DST/RRAB	NOTE 3(b)	2	12/31/88	NA
II.C.3	Systems Interaction	Pittman	NRR/DST/GIB	A-17	2	12/31/88	NA
II.C.4	Reliability Engineering	Pittman	RES/DRPS/RHFB	NOTE 3(b)	2	12/31/88	NA
II.D	REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES						
II.D.1	Testing Requirements	-	NRR/DL	I	1	06/30/89	F-14
II.D.2	Research on Relief and Safety Valve Test Requirements	Riggs	RES	LOW	1	06/30/89	NA
II.D.3	Relief and Safety Valve Position Indication	-	NRR	I	1	06/30/89	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.E	SYSTEM DESIGN						
II.E.1	Auxiliary Feedwater System						
II.E.1.1	Auxiliary Feedwater System Evaluation	-	NRR/DL	I	1	12/31/86	F-15
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	-	NRR/DL	I	1	12/31/86	F-16, F-17
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	Riggs	RES/DRA/RRBR	NOTE 3(a)	1	12/31/86	
II.E.2	Emergency Core Cooling System						
II.E.2.1	Reliance on ECCS	Riggs	NRR/DSI/RSB	II.K.3(17)	1	12/31/85	NA
II.E.2.2	Research on Small Break LOCAs and Anomalous Transients	Riggs	RES/DAE/RSRB	NOTE 3(b)	1	12/31/85	NA
II.E.2.3	Uncertainties in Performance Predictions	V'Molen	NRR/DSI/RSB	LOW	1	12/31/85	NA
II.E.3	Decay Heat Removal						
II.E.3.1	Reliability of Power Supplies for Natural Circulation	-	NRR	I			
II.E.3.2	Systems Reliability	V'Molen	NRR/DST/GIB	A-45		11/30/83	NA
II.E.3.3	Coordinated Study of Shutdown Heat Removal Requirements	V'Molen	NRR/DST/GIB	A-45		11/30/83	NA
II.E.3.4	Alternate Concepts Research	Riggs	RES/DAE/FBRB	NOTE 3(b)		11/30/83	NA
II.E.3.5	Regulatory Guide	Riggs	NRR/DST/GIB	A-45		11/30/83	NA
II.E.4	Containment Design						
II.E.4.1	Dedicated Penetrations	-	NRR/DL	I		06/30/88	F-18
II.E.4.2	Isolation Dependability	-	NRR/DL	I		06/30/88	F-19
II.E.4.3	Integrity Check	Milstead	RES/DRPS/RPSI	NOTE 3(b)		06/30/88	NA
II.E.4.4	Purging	-	-	-			
II.E.4.4(1)	Issue Letter to Licensees Requesting Limited Purging	Milstead	NRR/DSI/CSB	NOTE 3(a)		06/30/88	
II.E.4.4(2)	Issue Letter to Licensees Requesting Information on Isolation Letter	Milstead	NRR/DSI/CSB	NOTE 3(a)		06/30/88	
II.E.4.4(3)	Issue Letter to Licensees on Valve Operability	Milstead	NRR/DSI/CSB	NOTE 3(a)		06/30/88	
II.E.4.4(4)	Evaluate Purging and Venting During Normal Operation	Milstead	NRR/DSI/CSB	NOTE 3(b)		06/30/88	NA
II.E.4.4(5)	Issue Modified Purging and Venting Requirement	Milstead	NRR/DSI/CSB	NOTE 3(b)		06/30/88	NA
II.E.5	Design Sensitivity of B&W Reactors						
II.E.5.1	Design Evaluation	Thatcher	NRR/DSI/RSB	NOTE 3(a)	1	12/31/84	
II.E.5.2	B&W Reactor Transient Response Task Force	Thatcher	NRR/DL/ORAB	NOTE 3(a)	1	12/31/84	
II.E.6	In Situ Testing of Valves						
II.E.6.1	Test Adequacy Study	Thatcher	RES/DE/EIB	NOTE 3(a)	1	06/30/89	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.F	INSTRUMENTATION AND CONTROLS						
II.F.1	Additional Accident Monitoring Instrumentation	-	NRR/DL	I	2	06/30/89	F-20, F-21, F-22, F-23, F-24, F-25
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	-	NRR/DL	I	2	06/30/89	F-26
II.F.3	Instruments for Monitoring Accident Conditions	V'Molen	RES/DFO/ICBR	NOTE 3(a)	2	06/30/89	
II.F.4	Study of Control and Protective Action Design Requirements	Thatcher	NRR/DSI/ICSB	DROP	2	06/30/89	NA
II.F.5	Classification of Instrumentation, Control, and Electrical Equipment	Thatcher	RES/DE	LI (NOTE 3)	2	06/30/89	NA
II.G	ELECTRICAL POWER						
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	-	NRR	I			
II.H	TMI-2 CLEANUP AND EXAMINATION						
II.H.1	Maintain Safety of TMI-2 and Minimize Environmental Impact	Matthews	NRR/TMIPO	NOTE 3(b)		11/30/83	NA
II.H.2	Obtain Technical Data on the Conditions Inside the TMI-2 Containment Structure	Milstead	RES/DRAA/AEB	HIGH		11/30/83	
II.H.3	Evaluate and Feed Back Information Obtained from TMI	Milstead	NRR/TMIPO	II.H.2		11/30/83	NA
II.H.4	Determine Impact of TMI on Socioeconomic and Real Property Values	Milstead	RES/DHSWM/SEBR	LI (NOTE 3)		11/30/83	NA
II.J	GENERAL IMPLICATIONS OF TMI FOR DESIGN AND CONSTRUCTION ACTIVITIES						
II.J.1	Vendor Inspection Program						
II.J.1.1	Establish a Priority System for Conducting Vendor Inspections	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.1.2	Modify Existing Vendor Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.1.3	Increase Regulatory Control Over Present Non-Licensees	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.1.4	Assign Resident Inspectors to Reactor Vendors and Architect-Engineers	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.J.2	Construction Inspection Program						
II.J.2.1	Reorient Construction Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.2.2	Increase Emphasis on Independent Measurement in Construction Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.2.3	Assign Resident Inspectors to All Construction Sites	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.3	Management for Design and Construction						
II.J.3.1	Organization and Staffing to Oversee Design and Construction	Pittman	NRR/DHFS/LQB	I.B.1.1		11/30/83	NA
II.J.3.2	Issue Regulatory Guide	Pittman	NRR/DHFS/LQB	I.B.1.1		11/30/83	NA
II.J.4	Revise Deficiency Reporting Requirements						
II.J.4.1	Revise Deficiency Reporting Requirements	Riani	AEOD/DSP/ROAB	NOTE 2		11/30/83	
II.K	MEASURES TO MITIGATE SMALL-BREAK LOSS-OF-COOLANT ACCIDENTS AND LOSS-OF-FEEDWATER ACCIDENTS						
II.K.1	IE Bulletins	-	-	-			
II.K.1(1)	Review TMI-2 PNs and Detailed Chronology of the TMI-2 Accident	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(2)	Review Transients Similar to TMI-2 That Have Occurred at Other Facilities and NRC Evaluation of Davis-Besse Event	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(3)	Review Operating Procedures for Recognizing, Preventing, and Mitigating Void Formation in Transients and Accidents	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(4)	Review Operating Procedures and Training Instructions	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(5)	Safety-Related Valve Position Description	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(6)	Review Containment Isolation Initiation Design and Procedures	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(7)	Implement Positive Position Controls on Valves That Could Compromise or Defeat AFW Flow	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(8)	Implement Procedures That Assure Two Independent 100% AFW Flow Paths	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(9)	Review Procedures to Assure That Radioactive Liquids and Gases Are Not Transferred out of Containment Inadvertently	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(10)	Review and Modify Procedures for Removing Safety-Related Systems from Service	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(11)	Make All Operating and Maintenance Personnel Aware of the Seriousness and Consequences of the Erroneous Actions Leading up to, and in Early Phases of, the TMI-2 Accident	Emrit	NRR	NOTE 3(a)		12/31/84	-

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.K.1(12)	One Hour Notification Requirement and Continuous Communications Channels	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(13)	Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(14)	Review Operating Modes and Procedures to Deal with Significant Amounts of Hydrogen	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(15)	For Facilities with Non-Automatic AFW Initiation, Provide Dedicated Operator in Continuous Communication with CR to Operate AFW	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(16)	Implement Procedures That Identify PRZ PORV "Open" Indications and That Direct Operator to Close Manually at "Reset" Setpoint	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(17)	Trip PZR Level Bistable so That PZR Low Pressure Will Initiate Safety Injection	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(18)	Develop Procedures and Train Operators on Methods of Establishing and Maintaining Natural Circulation	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(19)	Describe Design and Procedure Modifications to Reduce Likelihood of Automatic PZR PORV Actuation in Transients	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(20)	Provide Procedures and Training to Operators for Prompt Manual Reactor Trip for LOFW, TT, MSIV Closure, LOOP, LOSG Level, and LO PZR Level	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(21)	Provide Automatic Safety-Grade Anticipatory Reactor Trip for LOFW, TT, or Significant Decrease in SG Level	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When FW System Not Operable	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(23)	Describe Uses and Types of RV Level Indication for Automatic and Manual Initiation Safety Systems	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(24)	Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and RCP Trip	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(25)	Develop Operator Action Guidelines	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(26)	Revise Emergency Procedures and Train ROs and SROs	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(27)	Provide Analyses and Develop Guidelines and Procedures for Inadequate Core Cooling Conditions	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(28)	Provide Design That Will Assure Automatic RCP Trip for All Circumstances Where Required	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.2	Commission Orders on B&W Plants	-	-	-			
II.K.2(1)	Upgrade Timeliness and Reliability of AFW System	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(2)	Procedures and Training to Initiate and Control AFW Independent of Integrated Control System	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.2(3)	Hard-Wired Control-Grade Anticipatory Reactor Trips	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(4)	Small-Break LOCA Analysis, Procedures and Operator Training	Emrit	NRR/DHFS/OLB	NOTE 3(a)		12/31/84	-

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.K.2(5)	Complete TMI-2 Simulator Training for All Operators	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.2(6)	Reevaluate Analysis for Dual-Level Setpoint Control	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(7)	Reevaluate Transient of September 24, 1977	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(8)	Continued Upgrading of AFW System	Emrit	NRR	II.E.1.1, II.E.1.2		12/31/84	NA
II.K.2(9)	Analysis and Upgrading of Integrated Control System	Emrit	NRR	I		12/31/84	F-27
II.K.2(10)	Hard-Wired Safety-Grade Anticipatory Reactor Trips	Emrit	NRR	I		12/31/84	F-28
II.K.2(11)	Operator Training and Drilling	Emrit	NRR	I		12/31/84	F-29
II.K.2(12)	Transient Analysis and Procedures for Management of Small Breaks	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.2(13)	Thermal-Mechanical Report on Effect of HPI on Vessel Integrity for Small-Break LOCA With No AFW	Emrit	NRR	I		12/31/84	F-30
II.K.2(14)	Demonstrate That Predicted Lift Frequency of PORVs and SVs Is Acceptable	Emrit	NRR	I		12/31/84	F-31
II.K.2(15)	Analysis of Effects of Slug Flow on Once-Through Steam Generator Tubes After Primary System Voiding	Emrit	NRR	I		12/31/84	-
II.K.2(16)	Impact of RCP Seal Damage Following Small-Break LOCA With Loss of Offsite Power	Emrit	NRR	I		12/31/84	F-32
II.K.2(17)	Analysis of Potential Voiding in RCS During Anticipated Transients	Emrit	NRR	I		12/31/84	F-33
II.K.2(18)	Analysis of Loss of Feedwater and Other Anticipated Transients	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.2(19)	Benchmark Analysis of Sequential AFW Flow to Once-Through Steam Generator	Emrit	NRR	I		12/31/84	F-34
II.K.2(20)	Analysis of Steam Response to Small-Break LOCA That Causes System Pressure to Exceed PORV Setpoint	Emrit	NRR	I		12/31/84	F-35
II.K.2(21)	LOFT L3-1 Predictions	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.3	Final Recommendations of Bulletins and Orders Task Force	-	-	-			
II.K.3(1)	Install Automatic PORV Isolation System and Perform Operational Test	Emrit	NRR	I		12/31/84	F-36
II.K.3(2)	Report on Overall Safety Effect of PORV Isolation System	Emrit	NRR	I		12/31/84	F-37
II.K.3(3)	Report Safety and Relief Valve Failures Promptly and Challenges Annually	Emrit	NRR	I		12/31/84	F-38
II.K.3(4)	Review and Upgrade Reliability and Redundancy of Non-Safety Equipment for Small-Break LOCA Mitigation	Emrit	NRR	II.C.1, II.C.2, II.C.3		12/31/84	NA
II.K.3(5)	Automatic Trip of Reactor Coolant Pumps	Emrit	NRR	I		12/31/84	F-39, G-01
II.K.3(6)	Instrumentation to Verify Natural Circulation	Emrit	NRR/DSI	I.C.1(3), II.F.2, II.F.3		12/31/84	NA
II.K.3(7)	Evaluation of PORV Opening Probability During Overpressure Transient	Emrit	NRR	I		12/31/84	-

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.K.3(8)	Further Staff Consideration of Need for Diverse Decay Heat Removal Method Independent of SGs	Emrit	NRR/DST/GIB	II.C.1, II.E.3.3		12/31/84	NA
II.K.3(9)	Proportional Integral Derivative Controller Modification	Emrit	NRR	I		12/31/84	F-40
II.K.3(10)	Anticipatory Trip Modification Proposed by Some Licensees to Confine Range of Use to High Power Levels	Emrit	NRR	I		12/31/84	F-41
II.K.3(11)	Control Use of PORV Supplied by Control Components, Inc. Until Further Review Complete	Emrit	NRR	I		12/31/84	-
II.K.3(12)	Confirm Existence of Anticipatory Trip Upon Turbine Trip	Emrit	NRR	I		12/31/84	F-42
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	Emrit	NRR	I		12/31/84	F-43
II.K.3(14)	Isolation of Isolation Condensers on High Radiation	Emrit	NRR	I		12/31/84	F-44
II.K.3(15)	Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems	Emrit	NRR	I		12/31/84	F-45
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification	Emrit	NRR	I		12/31/84	F-46
II.K.3(17)	Report on Outage of ECC Systems - Licensee Report and Technical Specification Changes	Emrit	NRR	I		12/31/84	F-47
II.K.3(18)	Modification of ADS Logic - Feasibility Study and Modification for Increased Diversity for Some Event Sequences	Emrit	NRR	I		12/31/84	F-48
II.K.3(19)	Interlock on Recirculation Pump Loops	Emrit	NRR	I		12/31/84	F-49
II.K.3(20)	Loss of Service Water for Big Rock Point	Emrit	NRR	I		12/31/84	-
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level - Design and Modification	Emrit	NRR	I		12/31/84	F-50
II.K.3(22)	Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design	Emrit	NRR	I		12/31/84	F-51
II.K.3(23)	Central Water Level Recording	Emrit	NRR	I.D.2, III.A.1.2(1), III.A.3.4		12/31/84	NA
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	Emrit	NRR	I		12/31/84	F-52
II.K.3(25)	Effect of Loss of AC Power on Pump Seals	Emrit	NRR	I		12/31/84	F-53
II.K.3(26)	Study Effect on RHR Reliability of Its Use for Fuel Pool Cooling	Emrit	NRR/DSI	II.E.2.1		12/31/84	NA
II.K.3(27)	Provide Common Reference Level for Vessel Level Instrumentation	Emrit	NRR	I		12/31/84	F-54
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	Emrit	NRR	I		12/31/84	F-55
II.K.3(29)	Study to Demonstrate Performance of Isolation Condensers with Non-Condensibles	Emrit	NRR	I		12/31/84	F-56
II.K.3(30)	Revised Small-Break LOCA Methods to Show Compliance with 10 CFR 50, Appendix K	Emrit	NRR	I		12/31/84	F-57
II.K.3(31)	Plant-Specific Calculations to Show Compliance with 10 CFR 50.46	Emrit	NRR	I		12/31/84	F-58

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
II.K.3(32)	Provide Experimental Verification of Two-Phase Natural Circulation Models	Emrit	NRR/DSI	II.E.2.2		12/31/84	NA
II.K.3(33)	Evaluate Elimination of PORV Function	Emrit	NRR	II.C.1		12/31/84	NA
II.K.3(34)	Relap-4 Model Development	Emrit	NRR/DSI	II.E.2.2		12/31/84	NA
II.K.3(35)	Evaluation of Effects of Core Flood Tank Injection on Small-Break LOCAs	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(36)	Additional Staff Audit Calculations of B&W Small-Break LOCA Analyses	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(37)	Analysis of B&W Response to Isolated Small-Break LOCA	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(38)	Analysis of Plant Response to a Small-Break LOCA in the Pressurizer Spray Line	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(39)	Evaluation of Effects of Water Slugs in Piping Caused by HPI and CFT Flows	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(40)	Evaluation of RCP Seal Damage and Leakage During a Small-Break LOCA	Emrit	NRR	II.K.2(16)		12/31/84	NA
II.K.3(41)	Submit Predictions for LOFT Test L3-6 with RCPs Running	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(42)	Submit Requested Information on the Effects of Non-Condensible Gases	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(43)	Evaluation of Mechanical Effects of Slug Flow on Steam Generator Tubes	Emrit	NRR	II.K.2(15)		12/31/84	NA
II.K.3(44)	Evaluation of Anticipated Transients with Single Failure to Verify No Significant Fuel Failure	Emrit	NRR	I		12/31/84	F-59
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	Emrit	NRR	I		12/31/84	F-60
II.K.3(46)	Response to List of Concerns from ACRS Consultant	Emrit	NRR	I		12/31/84	F-61
II.K.3(47)	Test Program for Small-Break LOCA Model Verification Pretest Prediction, Test Program, and Model Verification	Emrit	NRR	I.C.1(3), II.E.2.2		12/31/84	NA
II.K.3(48)	Assess Change in Safety Reliability as a Result of Implementing B&OTF Recommendations	Emrit	NRR	II.C.1, II.C.2		12/31/84	NA
II.K.3(49)	Review of Procedures (NRC)	Emrit	NRR/DHFS/PSRB	I.C.8, I.C.9		12/31/84	NA
II.K.3(50)	Review of Procedures (NSSS Vendors)	Emrit	NRR/DHFS/PSRB	I.C.7, I.C.9		12/31/84	NA
II.K.3(51)	Symptom-Based Emergency Procedures	Emrit	NRR/DHFS/PSRB	I.C.9		12/31/84	NA
II.K.3(52)	Operator Awareness of Revised Emergency Procedures	Emrit	NRR	I.B.1.1, I.C.2, I.C.5		12/31/84	NA
II.K.3(53)	Two Operators in Control Room	Emrit	NRR	I.A.1.3		12/31/84	NA
II.K.3(54)	Simulator Upgrade for Small-Break LOCAs	Emrit	NRR	I.A.4.1(2)		12/31/84	NA
II.K.3(55)	Operator Monitoring of Control Board	Emrit	NRR	I.C.1(3), I.D.2, I.D.3		12/31/84	NA
II.K.3(56)	Simulator Training Requirements	Emrit	NRR/DHFS/OLB	I.A.2.6(3), I.A.3.1		12/31/84	NA
II.K.3(57)	Identify Water Sources Prior to Manual Activation of ADS	Emrit	NRR	I		12/31/84	F-62

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
III.A	EMERGENCY PREPAREDNESS AND RADIATION EFFECTS						
III.A.1	Improve Licensee Emergency Preparedness - Short Term						
III.A.1.1	Upgrade Emergency Preparedness	-	-	-			
III.A.1.1(1)	Implement Action Plan Requirements for Promptly Improving Licensee Emergency Preparedness	-	OIE/DEPER/EPB	I			
III.A.1.1(2)	Perform an Integrated Assessment of the Implementation	-	OIE/DEPER/EPB	I			
III.A.1.2	Upgrade Licensee Emergency Support Facilities	-	-	-			
III.A.1.2(1)	Technical Support Center	-	OIE/DEPER/EPB	I			F-63
III.A.1.2(2)	On-Site Operational Support Center	-	OIE/DEPER/EPB	I			F-64
III.A.1.2(3)	Near-Site Emergency Operations Facility	-	OIE/DEPER/EPB	I			F-65
III.A.1.3	Maintain Supplies of Thyroid-Blocking Agent	-	-	-			
III.A.1.3(1)	Workers	Riggs	OIE/DEPER/EPB	NOTE 3(b)	1	12/31/85	NA
III.A.1.3(2)	Public	Riggs	OIE/DEPER/EPB	NOTE 3(b)	1	12/31/85	NA
III.A.2	Improving Licensee Emergency Preparedness-Long Term						
III.A.2.1	Amend 10 CFR 50 and 10 CFR 50, Appendix E	-	-	-			
III.A.2.1(1)	Publish Proposed Amendments to the Rules	-	RES	I			
III.A.2.1(2)	Conduct Public Regional Meetings	-	RES	I			
III.A.2.1(3)	Prepare Final Commission Paper Recommending Adoption of Rules	-	RES	I			
III.A.2.1(4)	Revise Inspection Program to Cover Upgraded Requirements	-	OIE	I			F-67
III.A.2.2	Development of Guidance and Criteria	-	NRR/DL	I			F-68
III.A.3	Improving NRC Emergency Preparedness						
III.A.3.1	NRC Role in Responding to Nuclear Emergencies	-	-	-			
III.A.3.1(1)	Define NRC Role in Emergency Situations	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.1(2)	Revise and Upgrade Plans and Procedures for the NRC Emergency Operations Center	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.1(3)	Revise Manual Chapter 0502, Other Agency Procedures, and NUREG-0610	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.1(4)	Prepare Commission Paper	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.1(5)	Revise Implementing Procedures and Instructions for Regional Offices	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.2	Improve Operations Centers	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.3	Communications	-	-	-			
III.A.3.3(1)	Install Direct Dedicated Telephone Lines	Pittman	OIE/DEPER/IRDB	NOTE 3(a)	1	6/30/85	NA
III.A.3.3(2)	Obtain Dedicated, Short-Range Radio Communication Systems	Pittman	OIE/DEPER/IRDB	NOTE 3(a)	1	6/30/85	NA
III.A.3.4	Nuclear Data Link	Thatcher	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	
III.A.3.5	Training, Drills, and Tests	Pittman	OIE/DEPER/IRDB	NOTE 3(b)	1	6/30/85	NA
III.A.3.6	Interaction of NRC and Other Agencies	-	-	-			
III.A.3.6(1)	International	Pittman	OIE/DEPER/EPLB	NOTE 3(b)	1	6/30/85	NA
III.A.3.6(2)	Federal	Pittman	OIE/DEPER/EPLB	NOTE 3(b)	1	6/30/85	NA
III.A.3.6(3)	State and Local	Pittman	OIE/DEPER/EPLB	NOTE 3(b)	1	6/30/85	NA

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
III.B	EMERGENCY PREPAREDNESS OF STATE AND LOCAL GOVERNMENTS						
III.B.1	Transfer of Responsibilities to FEMA	Milstead	OIE/DEPER/IRDB	NOTE 3(b)		11/30/83	NA
III.B.2	Implementation of NRC and FEMA Responsibilities	-	-	-			
III.B.2(1)	The Licensing Process	Milstead	OIE/DEPER/IRDB	NOTE 3(b)		11/30/83	NA
III.B.2(2)	Federal Guidance	Milstead	OIE/DEPER/IRDB	NOTE 3(b)		11/30/83	NA
III.C	PUBLIC INFORMATION						
III.C.1	Have Information Available for the News Media and the Public	-	-	-			
III.C.1(1)	Review Publicly Available Documents	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.1(2)	Recommend Publication of Additional Information	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.1(3)	Program of Seminars for News Media Personnel	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.2	Develop Policy and Provide Training for Interfacing With the News Media	-	-	-			
III.C.2(1)	Develop Policy and Procedures for Dealing With Briefing Requests	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.2(2)	Provide Training for Members of the Technical Staff	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.D	RADIATION PROTECTION						
III.D.1	Radiation Source Control						
III.D.1.1	Primary Coolant Sources Outside the Containment Structure	-	-	-			
III.D.1.1(1)	Review Information Submitted by Licensees Pertaining to Reducing Leakage from Operating Systems	-	NRR	I	1	12/31/88	
III.D.1.1(2)	Review Information on Provisions for Leak Detection	Emrit	RES/DRA/ARGIB	DROP	1	12/31/88	
III.D.1.1(3)	Develop Proposed System Acceptance Criteria	Emrit	RES/DRA/ARGIB	DROP	1	12/31/88	
III.D.1.2	Radioactive Gas Management	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3	Ventilation System and Radioiodine Adsorber Criteria	-	-	-			
III.D.1.3(1)	Decide Whether Licensees Should Perform Studies and Make Modifications	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3(2)	Review and Revise SRP	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3(3)	Require Licensees to Upgrade Filtration Systems	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3(4)	Sponsor Studies to Evaluate Charcoal Adsorber	Emrit	NRR/DSI/METB	NOTE 3(b)	1	12/31/88	NA
III.D.1.4	Radwaste System Design Features to Aid in Accident Recovery and Decontamination	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.2	Public Radiation Protection Improvement						
III.D.2.1	Radiological Monitoring of Effluents	-	-	-			
III.D.2.1(1)	Evaluate the Feasibility and Perform a Value-Impact Analysis of Modifying Effluent-Monitoring Design Criteria	Emrit	NRR/DSI/METB	LOW	2	12/31/85	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
III.D.2.1(2)	Study the Feasibility of Requiring the Development of Effective Means for Monitoring and Sampling Noble Gases and Radioiodine Released to the Atmosphere	Emrit	NRR/DSI/METB	LOW	2	12/31/85	NA
III.D.2.1(3)	Revise Regulatory Guides	Emrit	NRR/DSI/METB	LOW	2	12/31/85	NA
III.D.2.2	Radioiodine, Carbon-14, and Tritium Pathway Dose Analysis	-	-	-			
III.D.2.2(1)	Perform Study of Radioiodine, Carbon-14, and Tritium Behavior	Emrit	NRR/DSI/RAB	NOTE 3(b)	2	12/31/85	NA
III.D.2.2(2)	Evaluate Data Collected at Quad Cities	Emrit	NRR/DSI/RAB	III.D.2.5	2	12/31/85	NA
III.D.2.2(3)	Determine the Distribution of the Chemical Species of Radioiodine in Air-Water-Steam Mixtures	Emrit	NRR/DSI/RAB	III.D.2.5	2	12/31/85	NA
III.D.2.2(4)	Revise SRP and Regulatory Guides	Emrit	NRR/DSI/RAB	III.D.2.5	2	12/31/85	NA
III.D.2.3	Liquid Pathway Radiological Control	-	-	-			
III.D.2.3(1)	Develop Procedures to Discriminate Between Sites/Plants	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.3(2)	Discriminate Between Sites and Plants That Require Consideration of Liquid Pathway Interdiction Techniques	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.3(3)	Establish Feasible Method of Pathway Interdiction	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.3(4)	Prepare a Summary Assessment	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.4	Offsite Dose Measurements	-	-	-			
III.D.2.4(1)	Study Feasibility of Environmental Monitors	V'Molen	NRR/DSI/RAB	NOTE 3(b)	2	12/31/85	NA
III.D.2.4(2)	Place 50 TLDs Around Each Site	V'Molen	OIE/DRP/ORPB	LI (NOTE 3)	2	12/31/85	NA
III.D.2.5	Offsite Dose Calculation Manual	V'Molen	NRR/DSI/RAB	NOTE 3(b)	2	12/31/85	NA
III.D.2.6	Independent Radiological Measurements	V'Molen	OIE/DRP/ORPB	LI (NOTE 3)	2	12/31/85	NA
III.D.3	Worker Radiation Protection Improvement						
III.D.3.1	Radiation Protection Plans	V'Molen	NRR/DSI/RAB	NOTE 3(b)	3	12/31/87	NA
III.D.3.2	Health Physics Improvements	-	-	-			
III.D.3.2(1)	Amend 10 CFR 20	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(2)	Issue a Regulatory Guide	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(3)	Develop Standard Performance Criteria	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(4)	Develop Method for Testing and Certifying Air-Purifying Respirators	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.3	In-plant Radiation Monitoring	-	-	-			
III.D.3.3(1)	Issue Letter Requiring Improved Radiation Sampling Instrumentation	-	NRR/DL	I	2		F-69
III.D.3.3(2)	Set Criteria Requiring Licensees to Evaluate Need for Additional Survey Equipment	-	NRR	NOTE 3(a)	2	12/31/86	NA
III.D.3.3(3)	Issue a Rule Change Providing Acceptable Methods for Calibration of Radiation-Monitoring Instruments	-	RES	NOTE 3(a)	2	12/31/86	NA
III.D.3.3(4)	Issue a Regulatory Guide	-	RES	NOTE 3(a)	2	12/31/86	NA
III.D.3.4	Control Room Habitability	-	NRR/DL	I			F-70
III.D.3.5	Radiation Worker Exposure	-	-	-			
III.D.3.5(1)	Develop Format for Data To Be Collected by Utilities Regarding Total Radiation Exposure to Workers	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA
III.D.3.5(2)	Investigative Methods of Obtaining Employee Health Data by Nonlegislative Means	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA
III.D.3.5(3)	Revise 10 CFR 20	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
IV.A	STRENGTHEN ENFORCEMENT PROCESS						
IV.A.1	Seek Legislative Authority	Emrit	GC	LI (NOTE 3)		11/30/83	NA
IV.A.2	Revise Enforcement Policy	Emrit	OIE/ES	LI (NOTE 3)		11/30/83	NA
IV.B	ISSUANCE OF INSTRUCTIONS AND INFORMATION TO LICENSEES						
IV.B.1	Revise Practices for Issuance of Instructions and Information to Licensees	Emrit	OIE/DEPER	LI (NOTE 3)		11/30/83	NA
IV.C	EXTEND LESSONS LEARNED TO LICENSED ACTIVITIES OTHER THAN POWER REACTORS						
IV.C.1	Extend Lessons Learned from TMI to Other NRC Programs	Emrit	NMSS/WM	NOTE 3(b)		11/30/83	NA
IV.D	NRC STAFF TRAINING						
IV.D.1	NRC Staff Training	Emrit	ADM/MDTS	LI (NOTE 3)		11/30/83	NA
IV.E	SAFETY DECISION-MAKING						
IV.E.1	Expand Research on Quantification of Safety Decision-Making	Colmar	RES/DRA/RABR	LI (NOTE 3)	2	12/31/86	NA
IV.E.2	Plan for Early Resolution of Safety Issues	Emrit	NRR/DST/SPEB	LI (NOTE 3)	2	12/31/86	NA
IV.E.3	Plan for Resolving Issues at the CP Stage	Colmar	RES/DRA/RABR	LI (NOTE 2)	2	12/31/86	NA
IV.E.4	Resolve Generic Issues by Rulemaking	Colmar	RES/DRA/RABR	LI (NOTE 3)	2	12/31/86	NA
IV.E.5	Assess Currently Operating Reactors	Matthews	NRR/DL/SEPB	NOTE 3(b)	2	12/31/86	NA
IV.F	FINANCIAL DISINCENTIVES TO SAFETY						
IV.F.1	Increased OIE Scrutiny of the Power-Ascension Test Program	Thatcher	OIE/DQASIP	NOTE 3(b)	1	12/31/86	NA
IV.F.2	Evaluate the Impacts of Financial Disincentives to the Safety of Nuclear Power Plants	Matthews	SP	NOTE 3(b)	1	12/31/86	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
IV.G	IMPROVE SAFETY RULEMAKING PROCEDURES						
IV.G.1	Develop a Public Agenda for Rulemaking	Emrit	ADM/RPB	LI (NOTE 3)	1	12/31/86	NA
IV.G.2	Periodic and Systematic Reevaluation of Existing Rules	Milstead	RES/DRA/RABR	LI (NOTE 3)	1	12/31/86	NA
IV.G.3	Improve Rulemaking Procedures	Milstead	RES/DRA/RABR	LI (NOTE 3)	1	12/31/86	NA
IV.G.4	Study Alternatives for Improved Rulemaking Process	Milstead	RES/DRA/RABR	LI (NOTE 3)	1	12/31/86	NA
IV.H	NRC PARTICIPATION IN THE RADIATION POLICY COUNCIL						
IV.H.1	NRC Participation in the Radiation Policy Council	Sege	RES/DHSWM/HEBR	LI (NOTE 3)		11/30/83	NA
V.A	DEVELOPMENT OF SAFETY POLICY						
V.A.1	Develop NRC Policy Statement on Safety	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.B	POSSIBLE ELIMINATION OF NONSAFETY RESPONSIBILITIES						
V.B.1	Study and Recommend, as Appropriate, Elimination of Nonsafety Responsibilities	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.C	ADVISORY COMMITTEES						
V.C.1	Strengthen the Role of Advisory Committee on Reactor Safeguards	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.C.2	Study Need for Additional Advisory Committees	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.C.3	Study the Need to Establish an Independent Nuclear Safety Board	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.D	LICENSING PROCESS						
V.D.1	Improve Public and Intervenor Participation in the Hearing Process	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.D.2	Study Construction-During-Adjudication Rules	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.D.3	Reexamine Commission Role in Adjudication	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.D.4	Study the Reform of the Licensing Process	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.E	LEGISLATIVE NEEDS						
V.E.1	Study the Need for TMI-Related Legislation	Emrit	GC	LI (NOTE 5)		12/31/86	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
V.F	ORGANIZATION AND MANAGEMENT						
V.F.1	Study NRC Top Management Structure and Process	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.2	Reexamine Organization and Functions of the NRC Offices	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.3	Revise Delegations of Authority to Staff	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.4	Clarify and Strengthen the Respective Roles of Chairman, Commission, and Executive Director for Operations	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.5	Authority to Delegate Emergency Response Functions to a Single Commissioner	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.G	CONSOLIDATION OF NRC LOCATIONS						
V.G.1	Achieve Single Location, Long-Term	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.G.2	Achieve Single Location, Interim	Emrit	GC	LI (NOTE 3)		12/31/86	NA
	TASK ACTION PLAN ITEMS						
A-1	Water Hammer (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	NA
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	D-10
A-3	Westinghouse Steam Generator Tube Integrity (former USI)	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	12/31/88	
A-4	CE Steam Generator Tube Integrity (former USI)	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	12/31/88	
A-5	B&W Steam Generator Tube Integrity (former USI)	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	12/31/88	
A-6	Mark I Short-Term Program (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	
A-7	Mark I Long-Term Program (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	D-01
A-8	Mark II Containment Pool Dyanmic Loads Long-Term Program (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	NA
A-9	ATWS (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	
A-10	BWR Feedwater Nozzle Cracking (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	B-25
A-11	Reactor Vessel Materials Toughness (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	NA
A-13	Snubber Operability Assurance	Emrit	NRR/DE/MEB	NOTE 3(a)		11/30/83	
A-14	Flaw Detection	Matthews	NRR/DE/MTEB	DROP		11/30/83	NA
A-15	Primary Coolant System Decontamination and Steam Generator Chemical Cleaning	Pittman	NRR/DE/CHEB	NOTE 3(b)		11/30/83	NA
A-16	Steam Effects on BWR Core Spray Distribution	Emrit	NRR/DSI/CPB	NOTE 3(a)		11/30/83	D-12
A-17	Systems Interaction	-	RES/DSIR/EIB	USI		11/30/83	
A-18	Pipe Rupture Design Criteria	Emrit	NRR/DE/MEB	DROP		11/30/83	NA
A-19	Digital Computer Protection System	Thatcher	NRR/DSI/ICSB	NOTE 4		11/30/83	
A-20	Impacts of the Coal Fuel Cycle	-	NRR/DE/EHEB	LI (NOTE 5)		11/30/83	NA
A-21	Main Steamline Break Inside Containment - Evaluation of Environmental Conditions for Equipment Qualification	V'Molen	NRR/DSI/CSB	LOW		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
A-22	PWR Main Steamline Break - Core, Reactor Vessel and Containment Building Response	V'Molen	NRR/DSI/CSB	DROP		11/30/83	NA
A-23	Containment Leak Testing	Matthews	NRR/DSI/CSB	RI (NOTE 5)		11/30/83	
A-24	Qualification of Class 1E Safety-Related Equipment (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	B-60
A-25	Non-Safety Loads on Class 1E Power Sources	Thatcher	NRR/DSI/PSB	NOTE 3(a)		11/30/83	
A-26	Reactor Vessel Pressure Transient Protection (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	B-04
A-27	Reload Applications	-	NRR/DSI/CPB	LI (NOTE 5)		11/30/83	NA
A-28	Increase in Spent Fuel Pool Storage Capacity	Colmar	NRR/DE/SGEB	NOTE 3(a)		11/30/83	
A-29	Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage	Colmar	RES/DRPS/RPSI	MEDIUM		11/30/83	
A-30	Adequacy of Safety-Related DC Power Supplies	Sege	NRR/DSI/PSB	128	1	12/31/86	NA
A-31	RHR Shutdown Requirements (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	
A-32	Missile Effects	Pittman	NRR/DE/MTEB	A-37, A-38, B-68		11/30/83	NA
A-33	NEPA Review of Accident Risks	-	NRR/DSI/AEB	EI(NOTE 3)		11/30/83	NA
A-34	Instruments for Monitoring Radiation and Process Variables During Accidents	V'Molen	NRR/DSI/ICSB	II.F.3		11/30/83	NA
A-35	Adequacy of Offsite Power Systems	Emrit	NRR/DSI/PSB	NOTE 3(a)		11/30/83	
A-36	Control of Heavy Loads Near Spent Fuel (former USI)	Emrit	NRR/DSI/GIB	NOTE 3(a)	1	6/30/85	C-10, C-15
A-37	Turbine Missiles	Pittman	NRR/DE/MTEB	DROP		11/30/83	NA
A-38	Tornado Missiles	Sege	NRR/DSI/ASB	LOW		11/30/83	NA
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	
A-40	Seismic Design Criteria - Short Term Program	-	RES/DSIR/EIB	USI		11/30/83	
A-41	Long Term Seismic Program	Colmar	NRR/DE/MEB	NOTE 3(b)	1	12/31/84	NA
A-42	Pipe Cracks in Boiling Water Reactors (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	6/30/85	B-05
A-43	Containment Emergency Sump Performance (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	12/31/87	
A-44	Station Blackout (former USI)	Emrit	RES/DRPS/RPSI	NOTE 3(a)	1	06/30/88	
A-45	Shutdown Decay Heat Removal Requirements (former USI)	Emrit	RES/DRPS/RPSI	NOTE 3(b)	1	12/31/88	NA
A-46	Seismic Qualification of Equipment in Operating Plants (former USI)	Emrit	NRR/DSRO/EIB	NOTE 3(a)	1	12/31/87	
A-47	Safety Implications of Control Systems	-	RES/DSIR/EIB	USI		11/30/83	
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	Emrit	NRR/DSIR/SAIB	NOTE 3(a)	1	06/30/89	
A-49	Pressurized Thermal Shock (former USI)	Emrit	NRR/DSRO/RSIB	NOTE 3(a)	1	12/31/87	A-21
B-1	Environmental Technical Specifications	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-2	Forecasting Electricity Demand	-	NRR	EI (NOTE 3)		11/30/83	NA
B-3	Event Categorization	-	NRR/DSI/RSB	LI (DROP)		11/30/83	NA
B-4	ECCS Reliability	Emrit	NRR/DSI/RSB	II.E.3.2		11/30/83	NA
B-5	Ductility of Two-Way Slabs and Shells and Buckling Behavior of Steel Containments	Thatcher	RES/DE/EIB	NOTE 3(b)	1	06/30/88	NA
B-6	Loads, Load Combinations, Stress Limits	Pittman	NRR/DSRO/EIB	119.1		12/31/87	NA
B-7	Secondary Accident Consequence Modeling	-	NRR/DSI/AEB	LI (DROP)		11/30/83	NA
B-8	Locking Out of ECCS Power Operated Valves	Riggs	NRR/DSI/RSB	DROP		11/30/83	NA
B-9	Electrical Cable Penetrations of Containment	Emrit	NRR/DSI/PSB	NOTE 3(b)		11/30/83	NA
B-10	Behavior of BWR Mark III Containments	V'Molen	NRR/DSI/CSB	NOTE 3(a)	1	12/31/84	NA
B-11	Subcompartment Standard Problems	-	NRR/DSI/CSB	LI (NOTE 5)		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
B-12	Containment Cooling Requirements (Non-LOCA)	Emrit	NRR/DSI/CSB	NOTE 3(b)	1	12/31/86	NA
B-13	Marviken Test Data Evaluation	-	NRR/DSI/CSB	LI (NOTE 5)		11/30/83	NA
B-14	Study of Hydrogen Mixing Capability in Containment Post-LOCA	Emrit	NRR/DST/GIB	A-48		11/30/83	NA
B-15	CONTEMPT Computer Code Maintenance	-	NRR/DSI/CSB	LI (DROP)		11/30/83	NA
B-16	Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	Emrit	NRR/DE/MEB	A-18		11/30/83	NA
B-17	Criteria for Safety-Related Operator Actions	Milstead	RES/DRPS/RHFB	MEDIUM	2	12/31/86	
B-18	Vortex Suppression Requirements for Containment Sumps	Emrit	NRR/DST/GIB	A-43		11/30/83	NA
B-19	Thermal-Hydraulic Stability	Colmar	NRR/DSI/CPB	NOTE 3(b)		6/30/85	NA
B-20	Standard Problem Analysis	-	RES/DAE/AMBR	LI (NOTE 5)		11/30/83	
B-21	Core Physics	-	NRR/DSI/CPB	LI (DROP)		11/30/83	NA
B-22	LWR Fuel	V'Molen	NRR/DSI/CPB	NOTE 4		11/30/83	
B-23	LMFBR Fuel	-	NRR/DSI/CPB	LI (DROP)		11/30/83	NA
B-24	Seismic Qualification of Electrical and Mechanical Components	Emrit	NRR	A-46		11/30/83	NA
B-25	Piping Benchmark Problems	-	NRR/DE/MEB	LI (NOTE 5)		11/30/83	
B-26	Structural Integrity of Containment Penetrations	Riggs	NRR/DE/MTEB	NOTE 3(b)	1	12/31/84	NA
B-27	Implementation and Use of Subsection NF	-	NRR/DE/MEB	LI (NOTE 5)		11/30/83	
B-28	Radionuclide/Sediment Transport Program	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-29	Effectiveness of Ultimate Heat Sinks	Pittman	NRR/DE/EHEB	NOTE 4		11/30/83	
B-30	Design Basis Floods and Probability	-	NRR/DE/EHEB	LI (NOTE 5)		11/30/83	
B-31	Dam Failure Model	Milstead	NRR/DE/SGEB	LI (DROP)	1	06/30/89	NA
B-32	Ice Effects on Safety-Related Water Supplies	Milstead	NRR/DE/EHEB	NOTE 4		11/30/83	
B-33	Dose Assessment Methodology	-	NRR/DSI/RAB	LI (NOTE 3)		11/30/83	NA
B-34	Occupational Radiation Exposure Reduction	Emrit	NRR/DSI/RAB	III.D.3.1		11/30/83	NA
B-35	Confirmation of Appendix I Models for Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Cooled Power Reactors	-	NRR/DSI/METB	LI (NOTE 5)		11/30/83	
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and for Normal Ventilation Systems	Emrit	NRR/DSI/METB	NOTE 3(a)		11/30/83	
B-37	Chemical Discharges to Receiving Waters	-	NRR/DE/EHEB	EI (NOTE 5)		11/30/83	
B-38	Reconnaissance Level Investigations	-	NRR/DE/EHEB	EI (DROP)		11/30/83	NA
B-39	Transmission Lines	-	NRR/DE/EHEB	EI (DROP)		11/30/83	NA
B-40	Effects of Power Plant Entrainment on Plankton	-	NRR/DE/EHEB	EI (DROP)		11/30/83	NA
B-41	Impacts on Fisheries	-	NRR/DE/EHEB	EI (DROP)		11/30/83	NA
B-42	Socioeconomic Environmental Impacts	-	NRR/DE/SAB	EI (NOTE 3)		11/30/83	NA
B-43	Value of Aerial Photographs for Site Evaluation	-	NRR/DE/EHEB	EI (NOTE 5)		11/30/83	
B-44	Forecasts of Generating Costs of Coal and Nuclear Plants	-	NRR/DE/SAB	EI (NOTE 3)		11/30/83	NA
B-45	Need for Power - Energy Conservation	-	NRR/DE/SAB	EI (B-2)		11/30/83	NA
B-46	Cost of Alternatives in Environmental Design	-	NRR/DE/SAB	EI (DROP)		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
B-47	Inservice Inspection of Supports-Classes 1, 2, 3, and MC Components	Colmar	NRR/DE/MTEB	DROP		11/30/83	NA
B-48	BWR CRD Mechanical Failure (Collet Housing)	Emrit	NRR/DE/MTEB	NOTE 3(b)		11/30/83	
B-49	Inservice Inspection Criteria and Corrosion Prevention Criteria for Containments	-	NRR	LI (NOTE 5)		11/30/83	
B-50	Post-Operating Basis Earthquake Inspection	Colmar	NRR/DE/SGEB	RI (LOW)	1	06/30/85	NA
B-51	Assessment of Inelastic Analysis Techniques for Equipment and Components	Emrit	NRR/DE/MEB	A-40		11/30/83	NA
B-52	Fuel Assembly Seismic and LOCA Responses	Emrit	NRR/DST/GIB	A-2		11/30/83	NA
B-53	Load Break Switch	Sege	NRR/DSI/PSB	RI (NOTE 3)		11/30/83	
B-54	Ice Condenser Containments	Milstead	NRR/DSI/CSB	NOTE 3(b)	1	12/31/84	NA
B-55	Improved Reliability of Target Rock Safety Relief Valves	V'Molen	RES/DE/EIB	MEDIUM		11/30/83	
B-56	Diesel Reliability	Milstead	RES/DRPS/RPSI	HIGH		11/30/83	D-19
B-57	Station Blackout	Emrit	NRR/DST/GIB	A-44		11/30/83	
B-58	Passive Mechanical Failures	Colmar	NRR/DE/EQB	NOTE 3(b)	1	12/31/85	NA
B-59	(N-1) Loop Operation in BWRs and PWRs	Colmar	NRR/DSI/RSB	RI (NOTE 3)	1	6/30/85	E-04,E-05
B-60	Loose Parts Monitoring System	Emrit	NRR/DSI/CPB	NOTE 3(b)	1	12/31/84	NA
B-61	Allowable ECCS Equipment Outage Periods	Pittman	RES/DRAA/PRAB	MEDIUM		11/30/83	
B-62	Reexamination of Technical Bases for Establishing SLs, LSSSs, and Reactor Protection System Trip Functions	-	NRR/DSI/CPB	LI (DROP)		11/30/83	NA
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	Emrit	NRR/DE/MEB	NOTE 3(a)		11/30/83	
B-64	Decommissioning of Reactors	Colmar	RES/DE/MEB	NOTE 2		11/30/83	
B-65	Iodine Spiking	Milstead	NRR/DSI/AEB	DROP	2	12/31/84	NA
B-66	Control Room Infiltration Measurements	Matthews	NRR/DSI/AEB	NOTE 3(a)		11/30/83	
B-67	Effluent and Process Monitoring Instrumentation	Colmar	NRR/DSI/METB	III.D.2.1		11/30/83	NA
B-68	Pump Overspeed During LOCA	Riani	NRR/DSI/ASB	DROP		11/30/83	NA
B-69	ECCS Leakage Ex-Containment	Riani	NRR/DSI/METB	III.D.1.1(1)		11/30/83	NA
B-70	Power Grid Frequency Degradation and Effect on Primary Coolant Pumps	Emrit	NRR/DSI/PSB	NOTE 3(a)		11/30/83	
B-71	Incident Response	Riani	NRR	III.A.3.1		11/30/83	NA
B-72	Health Effects and Life Shortening from Uranium and Coal Fuel Cycles	-	NRR/DSI/RAB	LI (NOTE 5)		11/30/83	NA
B-73	Monitoring for Excessive Vibration Inside the Reactor Pressure Vessel	Thatcher	NRR/DE/MEB	C-12		11/30/83	NA
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	Milstead	NRR/DE/EQB	NOTE 3(a)		11/30/83	
C-2	Study of Containment Depressurization by Inadvertent Spray Operation to Determine Adequacy of Containment External Design Pressure	Emrit	NRR/DSI/CSB	NOTE 3(b)		11/30/83	NA
C-3	Insulation Usage Within Containment	Emrit	NRR/DST/GIB	A-43		11/30/83	NA
C-4	Statistical Methods for ECCS Analysis	Riggs	NRR/DSRO/SPEB	RI (NOTE 3)	1	06/30/86	NA
C-5	Decay Heat Update	Riggs	NRR/DSRO/SPEB	RI (NOTE 3)	1	06/30/86	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
C-6	LOCA Heat Sources	Riggs	NRR/DSRO/SPEB	RI (NOTE 3)	1	06/30/86	NA
C-7	PWR System Piping	Emrit	NRR/DE/MTEB	NOTE 3(b)		11/30/83	NA
C-8	Main Steam Line Leakage Control Systems	Milstead	RES/DRPS/RPSI	HIGH		11/30/83	
C-9	RHR Heat Exchanger Tube Failures	V'Molen	NRR/DSI/RSB	DROP		11/30/83	NA
C-10	Effective Operation of Containment Sprays in a LOCA	Emrit	NRR/DSI/AEB	NOTE 3(a)		11/30/83	NA
C-11	Assessment of Failure and Reliability of Pumps and Valves	Emrit	NRR/DE/MEB	NOTE 3(b)		12/31/85	NA
C-12	Primary System Vibration Assessment	Thatcher	NRR/DE/MEB	NOTE 3(b)		11/30/83	NA
C-13	Non-Random Failures	Emrit	NRR/DST/GIB	A-17		11/30/83	NA
C-14	Storm Surge Model for Coastal Sites	Emrit	NRR/DE/EHEB	LI (DROP)		06/30/88	NA
C-15	NUREG Report for Liquids Tank Failure Analysis	-	NRR/DE/EHEB	LI (DROP)		11/30/83	NA
C-16	Assessment of Agricultural Land in Relation to Power Plant Siting and Cooling System Selection	-	NRR/DE/EHEB	EI (DROP)		11/30/83	NA
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	Emrit	NRR/DSI/METB	NOTE 3(a)		11/30/83	NA
D-1	Advisability of a Seismic Scram	Thatcher	RES/DET/MSEB	LOW		11/30/83	NA
D-2	Emergency Core Cooling System Capability for Future Plants	Emrit	RES/DRA/ARGIB	DROP		12/31/88	NA
D-3	Control Rod Drop Accident	Emrit	NRR/DSI/CPB	NOTE 3(b)		11/30/83	NA

NEW GENERIC ISSUES

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
1.	Failures in Air-Monitoring, Air-Cleaning, and Ventilating Systems	Emrit	NRR/DSI/METB	DROP		11/30/83	NA
2.	Failure of Protective Devices on Essential Equipment	Colmar	NRR/DSI/ICSB	NOTE 4		11/30/83	NA
3.	Set Point Drift in Instrumentation	Emrit	NRR/DSRO/RSIB	NOTE 3(b)	1	06/30/86	NA
4.	End-of-Life and Maintenance Criteria	Thatcher	NRR/DE/EQB	NOTE 3(b)		11/30/83	NA
5.	Design Check and Audit of Balance-of-Plant Equipment	Pittman	NRR/DSI/ASB	I.F.1		11/30/83	NA
6.	Separation of Control Rod from Its Drive and BWR High Rod Worth Events	V'Molen	NRR/DSI/CPB	NOTE 3(b)		11/30/83	NA
7.	Failures Due to Flow-Induced Vibrations	V'Molen	NRR/DSI/RSB	DROP		11/30/83	NA
8.	Inadvertent Actuation of Safety Injection in PWRs	Colmar	NRR/DSI/RSB	I.C.1		11/30/83	NA
9.	Reevaluation of Reactor Coolant Pump Trip Criteria	Emrit	NRR/DSI/RSB	II.K.3(5)		11/30/83	NA
10.	Surveillance and Maintenance of TIP Isolation Valves and Squib Charges	Riggs	NRR/DSI/ICSB	DROP		11/30/83	NA
11.	Turbine Disc Cracking	Pittman	NRR/DE/MTEB	A-37		11/30/83	NA
12.	BWR Jet Pump Integrity	Sege	NRR/DE/MTEB, MEB	NOTE 3(b)	1	12/31/84	NA
13.	Small Break LOCA from Extended Overheating of Pressurizer Heaters	Riani	NRR/DSI/RSB	DROP		11/30/83	NA
14.	PWR Pipe Cracks	Emrit	NRR/DE/MTEB	NOTE 3(b)	1	12/31/85	NA
15.	Radiation Effects on Reactor Vessel Supports	Emrit	NRR/DE/MTEB	HIGH	1	06/30/89	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
16.	BWR Main Steam Isolation Valve Leakage Control Systems	Milstead	NRR/DSI/ASB	C-8		11/30/83	NA
17.	Loss of Offsite Power Subsequent to LOCA	Colmar	NRR/DSI/PSB, ICSB	DROP		11/30/83	NA
18.	Steam Line Break with Consequential Small LOCA	Riggs	NRR/DSI/RSB	I.C.1		11/30/83	NA
19.	Safety Implications of Nonsafety Instrument and Control Power Supply Bus	Sege	NRR/DST/GIB	A-47		11/30/83	NA
20.	Effects of Electromagnetic Pulse on Nuclear Power Plants	Thatcher	NRR/DSI/ICSB	NOTE 3(b)	1	06/30/84	NA
21.	Vibration Qualification of Equipment	Riggs	NRR/DE/EIB	DROP	1	06/30/86	NA
22.	Inadvertent Boron Dilution Events	V'Molen	NRR/DSI/RSB	NOTE 3(b)	1	12/31/84	NA
23.	Reactor Coolant Pump Seal Failures	Riggs	RES/DE/EIB	HIGH		11/30/83	
24.	Automatic Emergency Core Cooling System Switch to Recirculation	V'Molen	NRR/DSI/RSB	NOTE 4		11/30/83	
25.	Automatic Air Header Dump on BWR Scram System	Milstead	NRR/DSI/RSB	NOTE 3(a)		11/30/83	
26.	Diesel Generator Loading Problems Related to SIS Reset on Loss of Offsite Power	Emrit	NRR/DSI/ASB	17		11/30/83	NA
27.	Manual vs. Automated Actions	Pittman	NRR/DSI/RSB	B-17		11/30/83	NA
28.	Pressurized Thermal Shock	Emrit	NRR/DST/GIB	A-49		11/30/83	NA
29.	Bolting Degradation or Failure in Nuclear Power Plants	V'Molen	RES/DE/EIB	HIGH		11/30/83	
30.	Potential Generator Missiles - Generator Rotor Retaining Rings	Pittman	NRR/DE/MEB	DROP	1	12/31/85	NA
31.	Natural Circulation Cooldown	Riggs	NRR/DSI/RSB	I.C.1		11/30/83	NA
32.	Flow Blockage in Essential Equipment Caused by Corbicula	Emrit	NRR/DSI/ASB	51		11/30/83	NA
33.	Correcting Atmospheric Dump Valve Opening Upon Loss of Integrated Control System Power	Pittman	NRR/DSI/ICSB	A-47		11/30/83	NA
34.	RCS Leak	Riggs	NRR/DHFS/PSRB	DROP	1	06/30/84	NA
35.	Degradation of Internal Appurtenances in LWRs	V'Molen	NRR/DSI/CPB, RSB	LOW	1	06/30/85	NA
36.	Loss of Service Water	Colmar	NRR/DSI/ASB, AEB, RSB	NOTE 3(b)	2	06/30/86	NA
37.	Steam Generator Overfill and Combined Primary and Secondary Blowdown	Colmar	NRR/DST/GIB, NRR/DSI/RSB	A-47, I.C.1(2)	1	06/30/85	NA
38.	Potential Recirculation System Failure as a Consequence of Injection of Containment Paint Flakes or Other Fine Debris	Milstead	RES	NOTE 4		11/30/83	
39.	Potential for Unacceptable Interaction Between the CRD System and Non-Essential Control Air System	Pittman	NRR/DSI/ASB	25		11/30/83	NA
40.	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	Colmar	NRR/DSI/ASB	NOTE 3(a)	1	06/30/84	B-65
41.	BWR Scram Discharge Volume Systems	V'Molen	NRR/DSI/RSB	NOTE 3(a)		11/30/83	B-58
42.	Combination Primary/Secondary System LOCA	Riggs	NRR/DSI/RSB	I.C.1	1	06/30/85	NA
43.	Reliability of Air Systems	Milstead	RES/DSIR/RPSI	NOTE 3(a)	2	12/31/88	
44.	Failure of Saltwater Cooling System	Milstead	NRR/DSI/ASB	43	1	12/31/88	NA

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
45.	Inoperability of Instrumentation Due to Extreme Cold Weather	Milstead	NRR/DSI/ICSB	NOTE 3(a)	1	06/30/84	
46.	Loss of 125 Volt DC Bus	Sege	NRR/DSI/PSB	76		11/30/83	NA
47.	Loss of Off-Site Power	Thatcher	NRR/DSI/RSB, ASB	NOTE 3(b)		11/30/83	
48.	LCO for Class 1E Vital Instrument Buses in Operating Reactors	Sege	NRR/DSI/PSB	128	1	12/31/86	NA
49.	Interlocks and LCOs for Redundant Class 1E Tie Breakers	Sege	NRR/DSI/PSB	128	2	12/31/86	NA
50.	Reactor Vessel Level Instrumentation in BWRs	Thatcher	NRR/DSI/RSB, ICSB	NOTE 3(b)	1	12/31/84	NA
51.	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems	Emrit	RES/DE/EIB	MEDIUM		11/30/83	
52.	SSW Flow Blockage by Blue Mussels	Emrit	NRR/DSI/ASB	51		11/30/83	NA
53.	Consequences of a Postulated Flow Blockage Incident in a BWR	V'Molen	NRR/DSI/CPB, RSB	DROP	1	12/31/84	NA
54.	Valve Operator-Related Events Occurring During 1978, 1979, and 1980	Colmar	NRR/DE/MEB	II.E.6.1	1	06/30/85	NA
55.	Failure of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand	Emrit	NRR/DSI/PSB	DROP	1	12/31/85	NA
56.	Abnormal Transient Operating Guidelines as Applied to a Steam Generator Overfill Event	Colmar	NRR/DHFS/HFEB	A-47, I.D.1		11/30/83	NA
57.	Effects of Fire Protection System Actuation on Safety-Related Equipment	Milstead	RES/DRA/ARGIB	MEDIUM	1	06/30/88	
58.	Inadvertent Containment Flooding	Sege	NRR/DSI/ASB, CSB	DROP		11/30/83	
59.	Technical Specification Requirements for Plant Shutdown when Equipment for Safe Shutdown is Degraded or Inoperable	Emrit	NRR/DST/TSIP	RI (NOTE 5)	1	06/30/85	NA
60.	Lamellar Tearing of Reactor Systems Structural Supports	Colmar	NRR/DST/GIB	A-12		11/30/83	NA
61.	SRV Line Break Inside the BWR Wetwell Airspace of Mark I and II Containments	Milstead	NRR/DSI/CSB	NOTE 3(b)	2	12/31/86	NA
62.	Reactor Systems Bolting Applications	Riggs	RES/DSIR/EIB	29	1	12/31/88	NA
63.	Use of Equipment Not Classified as Essential to Safety in BWR Transient Analysis	Pittman	RES	NOTE 4		11/30/83	
64.	Identification of Protection System Instrument Sensing Lines	Thatcher	NRR/DSI/ICSB	NOTE 3(b)		11/30/83	
65.	Probability of Core-Melt Due to Component Cooling Water System Failures	V'Molen	NRR/DSI/ASB	23	1	12/31/86	NA
66.	Steam Generator Requirements	Riggs	NRR/DEST/EMTB	NOTE 3(b)	2	12/31/88	NA
67.	Steam Generator Staff Actions	-	-	-		-	
67.2.1	Integrity of Steam Generator Tube Sleeves	Riggs	NRR/DE/MEB	RI (135)	1	06/30/85	NA
67.3.1	Steam Generator Overfill	Riggs	NRR/DST/GIB, NRR/DSI/RSB	A-47, I.C.1	1	06/30/85	NA
67.3.2	Pressurized Thermal Shock	Riggs	NRR/DST/GIB	A-49	1	06/30/85	NA
67.3.3	Improved Accident Monitoring	Riggs	NRR/DSI/ICSB	NOTE 3(a)	1	06/30/85	A-17

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
67.3.4	Reactor Vessel Inventory Measurement	Riggs	NRR/DSI/CPB	II.F.2	2	12/31/87	NA
67.4.1	RCP Trip	Riggs	NRR/DSI/RSB	II.K.3(5)	2	12/31/87	NA
67.4.2	Control Room Design Review	Riggs	NRR/DHFS/HFEB	I.D.1	2	12/31/87	NA
67.4.3	Emergency Operating Procedures	Riggs	NRC/DHFS/PSRB	I.C.1	2	12/31/87	NA
67.5.1	Reassessment of SGTR Design Basis	Riggs	RES/DRPS/RPSI	LI (NOTE 5)	2	12/31/87	NA
67.5.2	Reevaluation of SGTR Design Basis	Riggs	RES/DRPS/RPSI	LI (NOTE 5)	2	12/31/87	NA
67.5.3	Secondary System Isolation	Riggs	NRR/DSI/RSB	DROP	2	12/31/87	NA
67.6.0	Organizational Responses	Riggs	OIE/DEPER/IRDB	III.A.3	2	12/31/87	NA
67.7.0	Improved Eddy Current Tests	Riggs	RES/DE/EIB	135	2	12/31/87	NA
67.8.0	Denting Criteria	Riggs	NRR/DE/MTEB	RI (135)	2	12/31/87	NA
67.9.0	Reactor Coolant System Pressure Control	Riggs	NRR/DSI/GIB, NRR/DSI/RSB	A-45, I.C.1 (2,3)	2	12/31/87	NA
67.10.0	Supplement Tube Inspections	Riggs	NRR/DL/ORAB	LI (NOTE 5)	2	12/31/87	NA
68.	Postulated Loss of Auxiliary Feedwater System Resulting from Turbine-Driven Auxiliary Feedwater Pump Steam Supply Line Rupture	Pittman	NRR/DSI/ASB	124	2	12/31/86	NA
69.	Make-up Nozzle Cracking in B&W Plants	Colmar	NRR/DE/MEB, MTEB	NOTE 3(b)	1	12/31/84	B-43
70.	PORV and Block Valve Reliability	Riggs	RES/DE/EIB	MEDIUM	1	6/30/84	
71.	Failure of Resin Demineralizer Systems and Their Effects on Nuclear Power Plant Safety	Pittman	RES	NOTE 4		11/30/83	
72.	Control Rod Drive Guide Tube Support Pin Failures	Riggs	RES	NOTE 4		11/30/83	
73.	Detached Thermal Sleeves	Riggs	RES	NOTE 4		11/30/83	
74.	Reactor Coolant Activity Limits for Operating Reactors	Milstead	NRR/DSI/AEB	DROP	1	06/30/86	NA
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	Thatcher	RES/DRA/ARGIB	NOTE 1		11/30/83	B-76,B-77 B-78,B-79 B-80,B-81 B-82,B-85 B-86,B-87 B-88,B-89 B-90,B-91 B-92,B-93
76.	Instrumentation and Control Power Interactions	Pittman	RES/DRA/ARGIB	NOTE 4		11/30/83	
77.	Flooding of Safety Equipment Compartments by Back-flow Through Floor Drains	Colmar	RES/DE/EIB	A-17		12/31/87	NA
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	Riggs	RES/DRA/ARGIB	NOTE 4		11/30/83	
79.	Unanalyzed Reactor Vessel Thermal Stress During Natural Convection Cooldown	Colmar	RES/DE/EIB	MEDIUM	1	12/31/84	
80.	Pipe Break Effects on Control Rod Drive Hydraulic Lines in the Drywells of BWR Mark I and II Containments	V'Molen	NRR/DSI/RSB, ASB, CPB	LOW		11/30/83	NA
81.	Impact of Locked Doors and Barriers on Plant and Personnel Safety	Colmar	NRR/DHFS/PSRB	DROP	1	12/31/84	NA
82.	Beyond Design Basis Accidents in Spent Fuel Pools	V'Molen	RES/DRPS/RPSI	NOTE 3(b)	1	06/30/89	NA
83.	Control Room Habitability	Emrit	RES/DRAA/SAIB	NOTE 1	1	12/31/86	
84.	CE PORVs	Riggs	NRR/DEST/SRXB	NOTE 1	1	06/30/85	
85.	Reliability of Vacuum Breakers Connected to Steam Discharge Lines Inside BWR Containments	Milstead	NRR/DSI/CSB	DROP	1	12/31/85	NA

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	06/30/88	B-84
87.	Failure of HPCI Steam Line Without Isolation	Pittman	RES/DRPS/RPSI	HIGH		12/31/85	
88.	Earthquakes and Emergency Planning	Riggs	RES/DRA/ARGIB	NOTE 3(b)		12/31/87	NA
89.	Stiff Pipe Clamps	Riggs	RES	NOTE 4		(later)	
90.	Technical Specifications for Anticipatory Trips	V'Molen	NRR/DSI/RSB, ICSB	LOW		12/31/84	NA
91.	Main Crankshaft Failures in Transamerica DeLaval Emergency Diesel Generators	Emrit	RES/DRA/ARGIB	NOTE 3(b)		12/31/87	NA
92.	Fuel Crumbling During LOCA	V'Molen	NRR/DSI/RSB, CPB	LOW		12/31/84	NA
93.	Steam Binding of Auxiliary Feedwater Pumps	Pittman	RES/DRPS/RPSI	NOTE 3(a)		06/30/88	
94.	Additional Low Temperature Overpressure Protection Issues for Light Water Reactors	Pittman	RES/DRPS/RPSI	HIGH		13/31/85	
95.	Loss of Effective Volume for Containment Recirculation Spray	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
96.	RHR Suction Valve Testing	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
97.	PWR Reactor Cavity Uncontrolled Exposures	V'Molen	NRR/DSI/RAB	III.D.3.1		06/30/85	NA
98.	CRD Accumulator Check Valve Leakage	Pittman	NRR/DSI/ASB	DROP		06/30/85	NA
99.	RCS/RHR Suction Line Valve Interlock on PWRs	Pittman	RES/DRPS/RPSI	NOTE 3(a)	2	12/31/88	
100.	OTSG Level	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
101.	BWR Water Level Redundancy	V'Molen	RES/DE/EIB	NOTE 3(b)	1	06/30/89	NA
102.	Human Error in Events Involving Wrong Unit or Wrong Train	Emrit	NRR/DLPQ/LPEB	NOTE 3(b)	2	12/31/88	NA
103.	Design for Probable Maximum Precipitation	Emrit	RES/DE/EIB	NOTE 1		12/31/85	
104.	Reduction of Boron Dilution Requirements	Pittman	RES/DRA/ARGIB	DROP		12/31/88	NA
105.	Interfacing Systems LOCA at LWRs	Milstead	RES/DE/EIB	HIGH		06/30/85	
106.	Piping and Use of Highly Combustible Gases in Vital Areas	Milstead	RES/DRPS	MEDIUM		12/31/87	
107.	Main Transformer Failures	Milstead	RES	NOTE 4		(later)	
108.	BWR Suppression Pool Temperature Limits	Colmar	NRR/DSI/CSB	RI (LOW)		06/30/85	NA
109.	Reactor Vessel Closure Failure	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
110.	Equipment Protective Devices on Engineered Safety Features	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
111.	Stress Corrosion Cracking of Pressure Boundary Ferritic Steels in Selected Environments	Riggs	NRR/DE/MTEB	LI (NOTE 5)		12/31/85	NA
112.	Westinghouse RPS Surveillance Frequencies and Out-of-Service Times	Pittman	NRR/DSI/ICSB	RI (NOTE 3)		12/31/85	NA
113.	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers	Riggs	RES/DE/EIB	HIGH		12/31/87	
114.	Seismic-Induced Relay Chatter	Riggs	NRR/DSRO/SPEB	A-46		06/30/86	NA
115.	Enhancement of the Reliability of Westinghouse Solid State Protection System	Milstead	RES/DRPS/RPSI	NOTE 3(b)		06/30/89	NA
116.	Accident Management	Pittman	RES/DRA/ARGIB	NOTE 4		(later)	

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
117.	Allowable Outage Times for Diverse Simultaneous Equipment Outages	Pittman	RES/DRA/ARGIB	NOTE 4		(later)	
118.	Tendon Anchorage Failure	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
119.	Piping Review Committee Recommendations	-	-	-			
119.1	Piping Rupture Requirements and Decoupling of Seismic and LOCA Loads	Riggs	NRR/DE	RI (NOTE 5)		12/31/85	NA
119.2	Piping Damping Values	Riggs	NRR/DE	RI (NOTE 5)		12/31/85	NA
119.3	Decoupling the OBE from the SSE	Riggs	NRR/DE	RI (NOTE 5)		12/31/85	NA
119.4	BWR Piping Materials	Riggs	NRR/DE	RI (NOTE 5)		12/31/85	NA
119.5	Leak Detection Requirements	Riggs	NRR/DE	RI (NOTE 5)		12/31/85	NA
120.	On-Line Testability of Protection Systems	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
121.	Hydrogen Control for Large, Dry PWR Containments	Emrit	RES/DRA/RDE	HIGH		12/31/85	
122.	Davis-Besse Loss of All Feedwater Event of June 9, 1985: Short-Term Actions	-	-	-			
122.1	Potential Inability to Remove Reactor Decay Heat	-	-	-			
122.1.a	Failure of Isolation Valves in Closed Position	V'Molen	NRR/DSRO/RSIB	124	2	06/30/89	NA
122.1.b	Recovery of Auxiliary Feedwater	V'Molen	NRR/DSRO/RSIB	124	2	06/30/89	NA
122.1.c.	Interruption of Auxiliary Feedwater Flow	V'Molen	NRR/DSRO/RSIB	124	2	06/30/89	NA
122.2	Initiating Feed-and-Bleed	V'Molen	NRR/DEST/SRXB	NOTE 3(b)	2	06/30/89	NA
122.3	Physical Security System Constraints	V'Molen	NRR/DSRO/SPEB	LOW	2	06/30/89	NA
123.	Deficiencies in the Regulations Governing DBA and Single-Failure Criteria Suggested by the Davis-Besse Event of June 9, 1985	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
124.	Auxiliary Feedwater System Reliability	Emrit	NRR/DEST/SRXB	NOTE 3(a)	2	06/30/89	
125.	Davis-Besse Loss of All Feedwater Event of June 9, 1985: Long-Term Actions	-	-	-			
125.I.1	Availability of the STA	V'Molen	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.I.2	PORV Reliability	-	-	-	5	06/30/89	
125.I.2.a	Need for a Test Program to Establish Reliability of the PORV	V'Molen	NRR/DSRO/SPEB	70	5	06/30/89	NA
125.I.2.b	Need for PORV Surveillance Tests to Confirm Operational Readiness	V'Molen	NRR/DSRO/SPEB	70	5	06/30/89	NA
125.I.2.c	Need for Additional Protection Against PORV Failure	V'Molen	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.I.2.d	Capability of the PORV to Support Feed-and-Bleed	V'Molen	NRR/DSRO/SPEB	A-45	5	06/30/89	NA
125.I.3	SPDS Availability	Milstead	RES/DRA/ARGIB	NOTE 3(a)	5	06/30/89	
125.I.4	Plant-Specific Simulator	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.I.5	Safety Systems Tested in All Conditions Required by Design Basis Analysis	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.I.6	Valve Torque Limit and Bypass Switch Settings	V'Molen	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.I.7	Operator Training Adequacy	-	-	-			

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Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
125.I.7.a	Recover Failed Equipment	Pittman	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.I.7.b	Realistic Hands-On Training	V'Molen	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.I.8	Procedures and Staffing for Reporting to NRC Emergency Response Center	V'Molen	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.1	AFW System Evaluation	-	-	-			
125.II.1.a	Two-Train AFW Unavailability	V'Molen	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.II.1.b	Review Existing AFW Systems for Single Failure	V'Molen	NRR/DSRO/SPEB	124	5	06/30/89	NA
125.II.1.c	NUREG-0737 Reliability Improvements	V'Molen	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.II.1.d	AFW/Steam and Feedwater Rupture Control System/ICS Interactions in B&W Plants	V'Molen	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.II.2	Adequacy of Existing Maintenance Requirements for Safety-Related Systems	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.3	Review Steam/Feedline Break Mitigation Systems for Single Failure	V'Molen	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.II.4	Thermal Stress of OTSG Components	Riggs	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.II.5	Thermal-Hydraulic Effects of Loss and Restoration of Feedwater on Primary System Components	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	
125.II.6	Reexamine PRA-Based Estimates of the Likelihood of a Severe Core Damage Accident Based on Loss of All Feedwater	V'Molen	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.7	Reevaluate Provision to Automatically Isolate Feedwater from Steam Generator During a Line Break	V'Molen	RES/DRPS/RPSI	NOTE 3(b)	5	06/30/89	NA
125.II.8	Reassess Criteria for Feed-and-Bleed Initiation	V'Molen	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.9	Enhanced Feed-and-Bleed Capability	V'Molen	NRR/DSRO/SPEB	DROP	5	06/30/89	NA
125.II.10	Hierarchy of Impromptu Operator Actions	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.11	Recovery of Main Feedwater as Alternative to AFW	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.12	Adequacy of Training Regarding PORV Operation	Riggs	RES/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.13	Operator Job Aids	Pittman	NRR/DRA/ARGIB	DROP	5	06/30/89	NA
125.II.14	Remote Operation of Equipment Which Must Now Be Operated Locally	V'Molen	NRR/DSRO/SPEB	LOW	5	06/30/89	NA
126.	Reliability of PWR Main Steam Safety Valves	Riggs	RES/DRA/ARGIB	LI (NOTE 3)		06/30/88	NA
127.	Testing and Maintenance of Manual Valves in Safety-Related Systems	Pittman	RES/DRA/ARGIB	LOW		12/31/87	NA
128.	Electrical Power Reliability	Emrit	RES/DE/EIB	HIGH		12/31/86	
129.	Valve Interlocks to Prevent Vessel Drainage During Shutdown Cooling	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
130.	Essential Service Water Pump Failures at Multiplant Sites	Riggs	RES/DRPS/RPSI	HIGH		12/31/87	
131.	Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System in Westinghouse Plants	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
132.	RHR Pumps Inside Containment	Riggs	RES/DR	NOTE 4		(later)	
133.	Update Policy Statement on Nuclear Plant Staff Working Hours	Pittman	NRR/DLPQ/LHFB	LI (NOTE 5)		12/31/87	NA
134.	Rule on Degree and Experience Requirement	Pittman	RES/DRA/RDB	HIGH		12/31/87	
135.	Integrated Steam Generator Issues	Emrit	RES/DE/EIB	MEDIUM		12/31/87	
136.	Storage and Use of Large Quantities of Cryogenic Combustibles On Site	Milstead	RES/DRA/ARGIB	LI (NOTE 3)		06/30/88	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
137.	Refueling Cavity Seal Failure	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
138.	Deinerting Upon Discovery of RCS Leakage	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
139.	Thinning of Carbon Steel Piping in LWRs	Riggs	RES/DRA/ARGIB	RI (NOTE 3)		12/31/88	NA
140.	Fission Product Removal by Containment Sprays	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
141.	LBLOCA with Consequential SGTR	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
142.	Leakage Through Electrical Isolators	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
143.	Availability of Chilled Water Systems	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
144.	Scram Without a Turbine/Generator Trip	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
145.	Improve Surveillance and Startup Testing Programs	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
146.	Support Flexibility of Equipment and Components	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
147.	Fire-Induced Alternate Shutdown Control Room Panel Interactions	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
148.	Smoke Control and Manual Fire-Fighting Effectiveness	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
149.	Adequacy of Fire Barriers	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
150.	Overpressurization of Containment Penetrations	Milstead	RES/DRA/ARGIB	NOTE 4		(later)	
151.	Reliability of Recirculation Pump Trip During an ATWS	Riggs	RES/DRA/ARGIB	NOTE 4		(later)	
	HUMAN FACTORS ISSUES						
HF1	STAFFING AND QUALIFICATIONS						
HF1.1	Shift Staffing	Pittman	RES/DRPS/RHFB	NOTE 3(a)	2	06/30/89	
HF1.2	Engineering Expertise on Shift	Pittman	NRR/DHFT/HFIB	NOTE 3(b)	2	06/30/89	
HF1.3	Guidance on Limits and Conditions of Shift Work	Pittman	NRR/DHFT/HFIB	NOTE 3(b)	2	06/30/89	
HF2	TRAINING						
HF2.1	Evaluate Industry Training	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF2.2	Evaluate INPO Accreditation	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF2.3	Revise SRP Section 13.2	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF3	OPERATOR LICENSING EXAMINATIONS						
HF3.1	Develop Job Knowledge Catalog	Pittman	NRR/DHFT/HFIB	LI (NOTE 3)	2	12/31/87	NA
HF3.2	Develop License Examination Handbook	Pittman	NRR/DHFT/HFIB	LI (NOTE 3)	2	12/31/87	NA
HF3.3	Develop Criteria for Nuclear Power Plant Simulators	Pittman	NRR/DHFT/HFIB	I.A.4.2(4)	2	12/31/87	NA
HF3.4	Examination Requirements	Pittman	NRR/DHFT/HFIB	I.A.2.6(1)	2	12/31/87	NA
HF3.5	Develop Computerized Exam System	Pittman	NRR/DHFT/HFIB	LI (NOTE 3)	2	12/31/87	NA
HF4	PROCEDURES						
HF4.1	Inspection Procedure for Upgraded Emergency Operating Procedures	Pittman	NRR/DLPQ/LHFB	HIGH	2	06/30/89	
HF4.2	Procedures Generation Package Effectiveness Evaluation	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	2	06/30/89	NA
HF4.3	Criteria for Safety-Related Operator Actions	Pittman	NRR/DHFT/HFIB	B-17	2	06/30/89	NA
HF4.4	Guidelines for Upgrading Other Procedures	Pittman	RES/DRPS/RHFB	NOTE 3(b)	2	06/30/89	NA
HF4.5	Application of Automation and Artificial Intelligence	Pittman	NRR/DHFT/HFIB	HF5.2	2	06/30/89	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
HF5	MAN-MACHINE INTERFACE						
HF5.1	Local Control Stations	Pittman	RES/DRPS/RHFB	HIGH	1	12/31/86	
HF5.2	Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation	Pittman	RES/DRPS/RHFB	HIGH	1	12/31/86	
HF5.3	Evaluation of Operational Aid Systems	Pittman	NRR/DHFT/HFIB	HF5.2	1	12/31/86	NA
HF5.4	Computers and Computer Displays	Pittman	NRR/DHFT/HFIB	HF5.2	1	12/31/86	NA
HF6	MANAGEMENT AND ORGANIZATION						
HF6.1	Develop Regulatory Position on Management and Organization	Pittman	NRR/DHFT/HFIB	I.B.1.1 (1,2,3,4)	1	12/31/86	NA
HF6.2	Regulatory Position on Management and Organization at Operating Reactors	Pittman	NRR/DHFT/HFIB	I.B.1.1 (1,2,3,4)	1	12/31/86	NA
HF7	HUMAN RELIABILITY						
HF7.1	Human Error Data Acquisition	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF7.2	Human Error Data Storage and Retrieval	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF7.3	Reliability Evaluation Specialist Aids	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF7.4	Safety Event Analysis Results Applications	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF8	Maintenance and Surveillance Program	Pittman	NRR/DLPQ/LPEB	NOTE 3(b)	2	06/30/88	NA
	CHERNOBYL ISSUES						
CH1	ADMINISTRATIVE CONTROLS AND OPERATIONAL PRACTICES						
CH1.1	Administrative Controls to Ensure That Procedures Are Followed and That Procedures Are Adequate	-	-				
CH1.1A	Symptom-Based EOPs	Emrit	NRR/DLPQ/LHFB	LI (NOTE 5)		06/30/89	NA
CH1.1B	Procedure Violations	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH1.2	Approval of Tests and Other Unusual Operations	-	-				
CH1.2A	Test, Change, and Experiment Review Guidelines	Emrit	NRR/DOEA/OTSB	LI (NOTE 5)		06/30/89	NA
CH1.2B	NRC Testing Requirements	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH1.3	Bypassing Safety Systems	-	-				
CH1.3A	Revise Regulatory Guide 1.47	Emrit	RES/DE/EMEB	LI (NOTE 5)		06/30/89	NA
CH1.4	Availability of Engineered Safety Features	-	-				
CH1.4A	Engineered Safety Feature Availability	Emrit	NRR/DOEA/OTSB	LI (NOTE 5)		06/30/89	NA
CH1.4B	Technical Specifications Bases	Emrit	NRR/DOEA/OTSB	LI (NOTE 5)		06/30/89	NA
CH1.4C	Low Power and Shutdown	Emrit	RES/DSR/PRAB	LI (NOTE 5)		06/30/89	NA
CH1.5	Operating Staff Attitudes Toward Safety	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH1.6	Management Systems	-	-				
CH1.6A	Assessment of NRC Requirements on Management	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH1.7	Accident Management	-	-				
CH1.7A	Accident Management	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Priority Evaluation Engineer	Lead Office/ Division/ Branch	Safety Priority/ Status	Latest Revision	Latest Issuance Date	MPA No.
CH2	DESIGN						
CH2.1	Reactivity Accidents	-	-				
CH2.1A	Reactivity Transients	Emrit	RES/DSR/RPSB	LI (NOTE 5)		06/30/89	NA
CH2.2	Accidents at Low Power and at Zero Power	Emrit	RES/DRA/ARGIB	CH1.4		06/30/89	NA
CH2.3	Miltiple-Unit Protection	-	-				
CH2.3A	Control Room Habitability	Emrit	RES/DRA/ARGIB	83		06/30/89	NA
CH2.3B	Contamination Outside Control Room	Emrit	RES/DRA/ARGIB	LI (NOTE 5)		06/30/89	NA
CH2.3C	Smoke Control	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH2.3D	Shared Shutdown Systems	Emrit	RES/DRA/ARGIB	LI (NOTE 5)		06/30/89	NA
CH2.4	Fire Protection	-	-				
CH2.4A	Firefighting With Radiation Present	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH3	CONTAINMENT						
CH3.1	Containment Performance During Severe Accidents	-	-				
CH3.1A	Containment Performance	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH3.2	Filtered Venting	-	-				
CH3.2A	Filtered Venting	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH4	EMERGENCY PLANNING						
CH4.1	Size of the Emergency Planning Zones	Emrit	RES/DRA/ARGIB	LI (DROP)		06/30/89	NA
CH4.2	Medical Services	Emrit	RES/DRA/ARGIB	LI (DROP)		06/30/89	NA
CH4.3	Ingestion Pathway Measures	-	-				
CH4.3A	Ingestion Pathway Protective Measures	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH4.4	Decontamination and Relocation	-	-				
CH4.4A	Decontamination	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH4.4B	Relocation	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH5	SEVERE ACCIDENT PHENOMENA						
CH5.1	Source Term	-	-				
CH5.1A	Mechanical Dispersal in Fission Product Release	Emrit	RES/DSR/AEB	LI (NOTE 5)		06/30/89	NA
CH5.1B	Stripping in Fission Product Release	Emrit	RES/DSR/AEB	LI (NOTE 5)		06/30/89	NA
CH5.2	Steam Explosions	-	-				
CH5.2A	Steam Explosions	Emrit	RES/DSR/AEB	LI (NOTE 5)		06/30/89	NA
CH5.3	Combustible Gas	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH6	GRAPHITE-MODERATED REACTORS						
CH6.1	Graphite-Moderated Reactors	-	-				
CH6.1A	The Fort St. Vrain Reactor and the Modular HTGR	Emrit	RES/DRA/ARGIB	LI (DROP)		06/30/89	NA
CH6.1B	Structural Graphite Experiments	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH6.2	Assessment	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA

TABLE III

SUMMARY OF THE PRIORITIZATION OF ALL TMI ACTION PLAN ITEMS, TASK ACTION PLAN ITEMS, NEW GENERIC ISSUES, HUMAN FACTORS ISSUES, AND CHERNOBYL ISSUES

Legend

NOTES:
1 - Possible Resolution Identified for Evaluation
2 - Resolution Available
3 - Resolution Resulted in either the Establishment of New Requirements or No New Requirements
4 - Issues to be Prioritized in the Future
5 - Issue that is not a Generic Safety Issue but should be Assigned Resources for Completion

DROP	- Issue Dropped as a Generic Issue
EI	- Environmental Issue
GSI	- Generic Safety Issue
HIGH	- High Safety Priority
I	- TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737[98]
LI	- Licensing Issue
LOW	- Low Safety Priority
MEDIUM	- Medium Safety Priority
RI	- Regulatory Impact Issue
USI	- Unresolved Safety Issue

TABLE III (Continued)

ACTION ITEM/ISSUE GROUP	I	COVERED IN OTHER ISSUES	RESOLVED STAGES NOTE 1	NOTE 2	NOTE 3	USI	HIGH	MEDIUM	LOW	DROP	NOTE 4	NOTE 5	TOTAL
1. TMI ACTION PLAN ITEMS (369)													
(i) GSI	88	46	1	1	127	0	1	1	12	9	-	-	286
(ii) LI	-	0	-	1	74	-	-	-	-	0	0	8	83
2. TASK ACTION PLAN ITEMS (142)													
(i) USI	-	-	0	0	24	3	-	-	-	-	-	-	27
(ii) GSI	-	19	0	1	29	-	2	4	3	10	4	-	72
(iii) RI	-	0	0	0	5	-	-	-	1	0	0	1	7
(iv) LI	-	0	0	0	1	-	-	-	-	9	0	11	21
(v) EI	-	1	0	0	6	-	-	-	-	6	0	2	15
3. NEW GENERIC ISSUES (202)													
(i) GSI	-	46	4	0	33	0	11	6	7	39	38	-	184
(ii) RI	-	2	0	0	2	-	-	-	1	0	0	6	11
(iii) LI	-	0	0	0	2	-	-	-	-	0	0	5	7
4. HUMAN FACTORS ISSUES (27)													
(i) GSI	-	8	0	0	5	0	3	0	0	0	0	-	16
(ii) LI	-	0	0	0	3	-	-	-	-	-	0	8	11
5. CHERNOBYL ISSUES (32)													
(i) LI	-	2	0	0	4	-	-	-	-	3	0	23	32
TOTAL:	88	124	5	3	315	3	17	11	24	76	42	64	772

TABLE IV

LISTING OF AEOD REPORTS AND RELATED GENERIC ISSUES

This listing shows all AEOD reports that have been addressed either as completely new safety issues or as part of existing safety issues. It should be noted that, in some cases, more than one AEOD report has been generated on a single topic. However, all AEOD reports related to the identified safety issues are listed alphanumerically including those that have been superseded by other AEOD reports. The following is a description of the types of AEOD reports:

C - Reactor Case Study
E - Reactor Engineering Evaluation
S - Special Study Report
T - Technical Review Report

AEOD Report No.	AEOD Report Title	Related Safety Issue No.	Related AEOD Report
C001	Report on the Browns Ferry 3 Partial Failure to Scram Event on June 28, 1980	41	-
C003	Report on Loss of Offsite Power Event at Arkansas Nuclear One, Units 1 and 2	47	-
C004	AEOD Actions Concerning the Crystal River 3 Loss of Non-Nuclear Instrumentation and Integrated Control System Power on February 26, 1980	33	E122
C005	AEOD Observations and Recommendations Concerning the Problem of Steam Generator Overfill and Combined Primary and Secondary Side Blowdown	37, 42	-
C101	Report on the Saint Lucie 1 Natural Circulation Cooldown on June 11, 1980	31	-
C102	H. B. Robinson Reactor Coolant System Leak on January 29, 1981	34	-
C103	AEOD Safety Concerns Associated with Pipe Breaks in the BWR Scram System	40	-
C104	Millstone Unit 2 Loss of 125 V DC Bus Event on January 2, 1981	46	-
C105	Report on the Calvert Cliffs Unit 1 Loss of Service Water on May 20, 1980	36	-
C201	Safety Concern Associated with Reactor Vessel Level Instrumentation in Boiling Water Reactors	50, 101	-

TABLE IV (Continued)

AEOD Report No.	AEOD Report Title	Related Safety Issue No.	Related AEOD Report
C202	Report on Service Water System Flow Blockages by Bivalve Mollusks at Arkansas Nuclear One and Brunswick	32	E016
C203	Survey of Valve Operator-Related Events Occurring During 1978, 1979, and 1980	54	E305
C204	San Onofre Unit 1 Loss of Salt Water Cooling Event of March 10, 1980	44	-
C205	Abnormal Transient Operating Guidelines (ATOG) as Applied to the April 1981 Overfill Event at Arkansas Nuclear One, Unit 1	56	-
C301	Failures of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand	55	-
C401	Low Temperature Overpressure Events at Turkey Point Unit 4	94	E426
C403	Edwin I. Hatch Unit No. 2 Plant Systems Interaction Event on August 25, 1982	85	E322
C404	Steam Binding of Auxiliary Feedwater Pumps	93	E325
C501	Safety Implications Associated With In-Plant Pressurized Gas Storage and Distribution Systems in Nuclear Power Plants	106	E902
C503	Decay Heat Removal Problems at U.S. Pressurized Water Reactors	99	-
C701	Air Systems Reliability	43	E123
E002	BWR Jet Pump Integrity	12	-
E005	Operational Restrictions for Class 1E 120 VAC Vital Instrument Buses	48	-
E007	Potential for Unacceptable Interaction Between the Control Rod Drive System and Non-Essential Control Air System at the Browns Ferry Plant	39	-
E010	Tie Breaker Between Redundant Class 1E Buses - Point Beach Nuclear Plant, Units 1 and 2	49	-
E011	Concerns Relating to the Integrity of a Polymer Coating for Surfaces Inside Containment	38	-
E016	Flow Blockage in Essential Equipment at ANO Caused by Corbicula sp. (Asiatic Clams)	32	C202
E101	Degradation of Internal Appurtenances in LWR Piping	35	-
E112	Inoperability of Instrumentation Due to Extreme Cold Weather	45	E226
E122	AEOD Concern Regarding Inadvertent Opening of Atmospheric Dump Valves on B&W Plants During Loss of ICS/NNI Power	33	C004
E123	Common Cause Failure Potential at Rancho Seco - Desiccant Contamination of Air Lines	43	C701
E204	Effects of Fire Protection System Actuation on Safety-Related Equipment	57	-

TABLE IV (Continued)

AEOD Report No.	AEOD Report Title	Related Safety Issue No.	Related AEOD Report
E209	Generator Rotor Retaining Ring as a Potential Missile (Incident at Barseback 1 on 4/13/79)	30	-
E215	Engineering Evaluation of the Salt Service Water System Flow Blockage at the Pilgrim Nuclear Power Station by Blue Mussels	52	-
E226	Inoperability of Instrumentation Due to Extreme Cold Weather	45	E112
E304	Investigation of Backflow Protection in Common Equipment and Floor Drain Systems to Prevent Flooding of Vital Equipment in Safety-Related Compartments	77	-
E305	Inoperable Motor-Operated Valve Assemblies Due to Premature Degradation of Motors and/or Improper Limit Switch/Torque Switch Adjustment	54	C203
E322	Damage to Vacuum Breaker Valves as a Result of Relief Valve Lifting	85	C403
E325	Vapor Binding of Auxiliary Feedwater Pumps at Robinson 2	93	C404
E414	Stuck Open Isolation Check Valve on the Residual Heat Removal System at Hatch Unit 2	105	-
E417	Loosening of Flange Bolts on RHR Heat Exchanger Leading to Primary to Secondary Side Leakage	C-9	-
E426	Single Failure Vulnerability of Power Operated Relief Valve (PORV) Actuation Circuitry for Low Temperature Overpressure Protection (LTOP)	94	C401
E609	Inadvertent Draining of Reactor Vessel During Shutdown Cooling Operation	129	-
S401	Human Error in Events Involving Wrong Unit or Wrong Train	102	-
T302	Postulated Loss of Auxiliary Feedwater System Resulting from a Turbine Driven Auxiliary Feedwater Pump Steam Supply Line Rupture	68	-
T305	Flow Blockage in Essential Raw Cooling Water System Due to Asiatic Clam Instrusion at Sequoyah 1	51	-
T420	Failure of an Isolation Valve of the Reactor Core Isolation Cooling System to Open Against Operating Reactor Pressure	87	-

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TABLE V

SUMMARY OF CONSOLIDATED GENERIC ISSUES

This table shows the consolidation of those issues whose technical concerns were found to be addressed either partially or completely in other (major) issues. The table reflects the findings of the prioritization process that are summarized in Table II.

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues				
TMI ACTION PLAN ITEMS						
I.A.1.3	I	II.K.3(53)				
I.A.2.2.	NOTE 3(b)	I.A.2.6(3) [II.K.3(56)]				
I.A.2.6(1)	HIGH	I.B.1.1(6),	I.B.1.1(7),	HF3.4		
I.A.3.1	I	II.K.3(56)				
I.A.4.1(2)	NOTE 3(a)	II.K.3(54)				
I.A.4.2(4)	HIGH	HF3.3				
I.B.1.1 (1,2,3,4)	NOTE 3(b)	II.J.3.1,	II.J.3.2,	II.K.3(52),	HF6.1,	HF6.2
I.C.1		8, 67.4.3,	18, 67.9.0	31,	47,	67.3.1,
I.C.1(2)	I	37				
I.C.1(3)	I	II.K.2(12), II.K.3(37), II.K.3(47),	II.K.2(18), II.K.3(38), II.K.3(55),	II.K.3(6), II.K.3(39), 37	II.K.3(35), II.K.3(41),	II.K.3(36), II.K.3(42),
I.C.2	I	II.K.3(52)				
I.C.5	I	II.K.3(52)				
I.C.7	I	II.K.3(50)				
I.C.8	I	II.K.3(49)				
I.C.9	I	II.K.3(49),	II.K.3(50)	II.K.3(51)		
I.D.1	I	56,	67.4.2			
I.D.2	I	II.K.3(23),	II.K.3(55)			

TABLE V (cont)

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues			
I.D.3	MEDIUM	II.K.3(55)			
I.F.1	HIGH	5			
II.B.8	NOTE 3(a)	II.B.7			
II.C.1	NOTE 3(b)	II.K.3(4),	II.K.3(8),	II.K.3(33),	II.K.3(48)
II.C.2	NOTE 3(b)	II.K.3(4),	II.K.3(48)		
II.E.1.1	I	II.K.2(8)			
II.E.1.2	I	II.K.2(8)			
II.E.2.2	NOTE 3(b)	II.K.3(32),	II.K.3(34),	II.K.3(47)	
II.E.6.1	NOTE 3(a)	54			
II.F.2	I	II.K.3(6),	67.3.4		
II.F.3	NOTE 3(a)	II.K.3(6),	A-34		
II.H.2	HIGH	II.H.3			
II.K.2(15)	I	II.K.3(43)			
II.K.2(16)	I	II.K.3(40)			
II.K.3(5)	I	9,	67.4.1		
II.K.3(17)	I	II.E.2.1[II.K.3(26)]			
III.A.1.2(1)	I	II.K.3(23)			
III.A.3.1	NOTE 3(b)	B-71			
III.A.3	NOTE 3	67.6.0			
III.A.3.4	NOTE 3(b)	II.K.3(23)			
III.D.1.1(1)	I	B-69			
III.D.2.1	LOW	B-67			
III.D.2.5	NOTE 3(b)	III.D.2.2(2),	III.D.2.2(3),	III.D.2.2(4)	
III.D.3.1	NOTE 3(b)	B-34,	97		

TABLE V (cont)

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues				
V.A.1	LI (NOTE 3)	II.A.2				
TASK ACTION PLAN ITEMS						
A-2	NOTE 3(a)	B-52				
A-12	NOTE 3(a)	60				
A-17	USI	II.C.3[II.K.3(4)],	C-13,	77		
A-18	DROP	B-16				
A-37	DROP	A-32,	11			
A-38	LOW	A-32				
A-40	USI	B-51				
A-43	NOTE 3(b)	B-18,	C-3			
A-44	NOTE 3(a)	B-57				
A-45	NOTE 3(b)	II.E.3.2[B-4],	II.E.3.3[II.K.3(8)],	II.E.3.5,	67.9.0,	125.I.2.d
A-46	NOTE 3(a)	B-24	114			
A-47	USI	19,	33,	37,	56,	67.3.1
A-48	NOTE 3(a)	B-14				
A-49	NOTE 3(a)	28,	67.3.2			
B-2	EI (NOTE 3)	B-45				
B-17	MEDIUM	27,	HF4.3			
B-68	DROP	A-32				
C-8	HIGH	16				
C-12	NOTE 3(b)	B-73				

TABLE V (cont)

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues				
NEW GENERIC ISSUES						
17	DROP	26				
23	HIGH	65				
25	NOTE 3(a)	39				
43	NOTE 3(a)	44				
51	MEDIUM	32,	52			
67.5.2	LI	36				
70	MEDIUM	125.I.2.a,	125.I.2.b			
75	NOTE 1	I.B.1.1(6),	I.B.1.1(7)			
76	NOTE 4	46				
119.1	RI	B-6				
124	NOTE 3(a)	68,	122.1.a,	122.1.b,	122.1.c,	125.II.1.b
128	HIGH	48,	49,	A-30		
135	MEDIUM	67.7				
HUMAN FACTORS ISSUES						
HF5.2	HIGH	HF4.5,	HF5.3,	HF5.4		

TASK I.F: QUALITY ASSURANCE

The objective of this task is to improve the quality assurance program for design, construction, and operations to provide greater assurance that plant design, construction, and operational activities are conducted in a manner commensurate with their importance to safety.

ITEM I.F.1: EXPAND QA LIST

DESCRIPTION

Historical Background

The TMI Action Plan[48] identified that "... several systems important to the safety of TMI were not designed, fabricated, and maintained at a level equivalent to their safety importance. They were not on the Quality Assurance (QA) List for the plant. This condition exists at other plants and results primarily from the lack of clarity in NRC guidance on graded protection... One of the difficulties in establishing a QA list based on safety importance is the absence of relative risk assignments to equipment." Evaluation of this issue included the consideration of Issue 5 listed in Section 1 of this report.

Possible Solution

The TMI Action Plan stated that "... NRC will develop guidance for licensees to expand their QA lists to cover equipment important to safety and rank the equipment in order of its importance to safety. Experience in use of the revised NRR review procedure for developing QA lists for individual operating license applicants will also be factored into the generic guidance to be developed and when determining backfit requirements..."[48] At the time this issue was identified, there was a task underway to define the applicability of 10 CFR 50, Appendix B, to 10 CFR 50, Appendix A, required equipment.

PRIORITY DETERMINATION

The principal benefits to be derived from an expanded QA list is the knowledge that adequate guidance is provided each licensee to establish QA programs and requirements which are commensurate with the safety importance of structures, systems, and components as determined from completed risk assessments. Currently, QA requirements are applied principally to structures, systems, and components that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public (10 CFR 50, Appendix B). This guidance will not only result in the inclusion or addition of other systems important to safety to each licensee's QA list which previously were excluded, but will also aid in clarifying the QA level of effort which is deemed necessary.

The gain in risk reduction is probably in some proportion to the difference between what would normally be the level of effort expended to the level now defined. Currently, there is no measure of risk variation which occurs as a function of the variance in QA level of effort. However, it appears reasonable to assume that a significant reduction in public risk could be achieved for those plants in which the QA levels would be held to the previous minimum acceptable level. Important questions to which we have no answers are: (1) the number of plants which would be designed, built, and maintained below the newly established quality acceptance level; and (2) how far below the new level would the QA programs of these plants have actually operated.

Cost Estimate

Industry Cost: It was estimated that: (1) the plant user cost will apply to 40 reactors currently in design and early construction; (2) on an average, it will require 0.5 man-year/reactor to develop an expanded QA list; (3) an additional 0.25 man-year/reactor over 4 years will be required to assure compliance to the added QA requirements; and (4) an additional 0.1 man-year/reactor for the 40 years operational life be expended to assure compliance to the expanded QA list during the operating life of a reactor. These estimates total 220 man-years. At a rate of $100,000/man-year, the total added cost to licensees is estimated to be $22M.

NRC Cost: The NRC costs were estimated in the TMI Action Plan[48] to be 2.5 man-years or $0.25M.

CONCLUSION

Although a value/impact assessment was not determined for this issue, the staff believed that the assurance afforded for safer operation justified a high priority ranking for this issue.

The original intent of this issue was to identify those systems, structures, and components beyond those labeled "safety-related," prioritize their importance to safety, and prepare a generic QA list. This was reflected in 10 CFR 50.34 (f)(3)(ii) which states: "...ensure that the Quality Assurance (QA) List required by Criteria II App. B, 10 CFR Part 50 includes all structures, systems and components important to safety (I.F.1)..." However, the staff's IREP Procedures Guide[812] failed to identify either the need for a QA list for structures, systems, and components important to safety (ITS) or the basis for a generic list even if one should be needed. The first four IREP studies performed at nuclear plants were reported in NUREG/CR-2787,[366] NUREG/CR-2802,[760] NUREG/CR-3085,[810] and NUREG/CR-3511.[811] The staff's resolution of the IREP issue is discussed in Item II.C.1.

In January 1984, Generic Letter 84-01[1177] was issued to clarify NRC use of the terms, "Important to Safety" and "Safety Related." This letter summarized NRC's intention to pursue QA requirements for important to safety equipment on a case-by-case basis. Further clarification was provided in the Commission's Memorandum and Order, CLI-84-9,[1178] in June 1984. The first proposed rule on ITS was presented in SECY-85-119[1179] and was later disapproved by the Commission who concluded that a specific listing of ITS equipment was not required to be maintained.[1180] Thus, the issue of an expansion of the QA list to cover ITS equipment was considered closed and the issue was not addressed in the second staff submittal on the ITS rule in SECY-86-164.[1181] Therefore, this issue was RESOLVED and no new requirements were established.[1182]

ITEM I.F.2: DEVELOP MORE DETAILED QA CRITERIA

DESCRIPTION

Historical Background

"Several systems important to the safety of TMI Unit 2 were not designed, fabricated, and maintained at a level equivalent to their safety importance. This condition exists at other plants and results primarily from the lack of clarity in NRC guidance for graded protection. This situation and other quality assurance problems relating to the quality assurance organization, authority, reporting, and inspection have been identified by the various TMI accident investigations and inquiries."[48]

Possible Solutions

The overall objective of this issue is the improvement of the QA program for design, construction, and operations to provide greater assurance that plant design, construction, and operational activities are conducted in a manner commensurate with their importance to safety. More detailed criteria for QA related to design, construction, and operations are proposed. The detailed criteria will consider the following:[48]

(1) Assure the independence of the organization performing the checking functions from the organization responsible for performing the tasks. For the construction phase, consider options for increasing the independence of the QA function. Include an option to require that licensees perform the entire quality assurance/quality control (QA/QC) function at construction sites. Consider using the third-party concept for accomplishing the NRC review and audit and making the QA/QC personnel agents of the NRC. Consider using INPO to enhance QA/QC independence.

(2) Include the QA personnel in the review and approval of plant operational maintenance and surveillance procedures and quality-related procedures associated with design, construction, and installation.

(3) Include the QA personnel in all activities involved in design, construction, installation, preoperational and startup testing, and operation.

(4) Establish criteria for determining QA requirements for specific classes of equipment such as instrumentation, mechanical equipment, and electrical equipment.

(5) Establish qualification requirements for QA and QC personnel.

(6) Increase the size of the licensees' QA staff.

(7) Clarify that the QA program is a condition of the construction permit and operating license and that substantive changes to an approved program must be submitted to NRC for review.

(8) Compare NRC QA requirements with those of other agencies (i.e., NASA, FAA, DOD) to improve NRC requirements.

(9) Clarify organizational reporting levels for the QA organization.

(10) Clarify requirements for maintenance of 'as built' documentation.

(11) Define role of QA in design and analysis activities. Obtain views on prevention of design errors from licensees, architect-engineers, and vendors

In the resolution of this issue, it was assumed that these criteria would be adopted for the nuclear industry.

PRIORITY DETERMINATION

The priority determination provided herein should not be construed to be the priority given to a QA program, rather it is the priority determination as regards the benefit of the above eleven items in improving QA.

It appears that the intent of this item was to provide more explicit and detailed criteria concerning the elements which are, in general, found in well conducted QA programs. It is inferred that providing these more detailed criteria will, in and of themselves, result in the establishment of QA programs of the caliber desired. Such programs it is believed will result in the detection of deficiencies in design, construction, and operation. To address this task adequately, the QA program must be independent of the performing organization; further, the QA organization must have the confidence and the ear of higher management so that QA concerns will be heard and acted upon. The deficiency of this effort is that the effectiveness of such a program is dependent on the acceptance, attitudes, and emphasis given by plant management as regards the benefits to be derived from such a QA program. Those utilities that place a high importance rating upon QA efforts will probably be able to incorporate the intent of this QA enhancement program without making major changes to their organizational structure or in the way they perform their plant operations. However, for those organizations that wish to do business "as usual," the changes may be more cosmetic than real. They will probably seek ways to establish a QA organization which on the surface appears good, but which in reality is a "paper tiger." As stated in SECY-82-352,[308] Enclosure 1, "In sum, the fundamental issues can best be characterized as a lack of total management commitment to quality and the uncertainty in industry's and NRC's ability to detect and correct the resulting deficiencies."

In conclusion, while this program may result in the establishment of an improved QA organizational structure at many facilities, the results depend heavily upon management acceptance. Lack of program implementation and management acceptance, rather than inadequate criteria as suggested by this issue, is the primary cause for current deficiencies in QA. Increasing the detail of the QA criteria has little potential for improving the quality of design, construction, or operation and, therefore, risk.

The items which address the concern stated above, Items I.F.2(2), I.F.2(3), I.F.2(6) and I.F.2(9), were included in the July 1981 revision to Chapter 17 of the SRP.[11]

CONCLUSION

It is believed that the issue of QA in nuclear power plants is an issue of high priority. However, we feel that the issue and solutions to QA deficiency as described herein [except for the completed issues I.F.2(2), I.F.2(3), I.F.2(6) and I.F.2(9)] fail to address the problem of management acceptance of QA programs. Hence, the residual items were given a low priority.

ITEM I.F.2(1): ASSURE THE INDEPENDENCE OF THE ORGANIZATION PERFORMING THE CHECKING FUNCTION

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

ITEM I.F.2(2): INCLUDE QA PERSONNEL IN REVIEW AND APPROVAL OF PLANT PROCEDURES

This item was evaluated in Item I.F.2 above and was determined to be RESOLVED. New requirements were established with changes to the SRP.[11]

ITEM I.F.2(3): INCLUDE QA PERSONNEL IN ALL DESIGN, CONSTRUCTION, INSTALLATION, TESTING, AND OPERATION ACTIVITIES

This item was evaluated in Item I.F.2 above and was determined to be RESOLVED. New requirements were established with changes to the SRP.[11]

ITEM I.F.2(4): ESTABLISH CRITERIA FOR DETERMINING QA REQUIREMENTS FOR SPECIFIC CLASSES OF EQUIPMENT

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

ITEM I.F.2(5): ESTABLISH QUALIFICATION REQUIREMENTS FOR QA AND QC PERSONNEL

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

ITEM I.F.2(6): INCREASE THE SIZE OF LICENSEES' QA STAFF

This item was evaluated in Item I.F.2 above and was determined to be RESOLVED. New requirements were established with changes to the SRP.[11]

ITEM I.F.2(7): CLARIFY THAT THE QA PROGRAM IS A CONDITION OF THE CONSTRUCTION PERMIT AND OPERATING LICENSE

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

ITEM I.F.2(8): COMPARE NRC QA REQUIREMENTS WITH THOSE OF OTHER AGENCIES

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

ITEM I.F.2(9): CLARIFY ORGANIZATIONAL REPORTING LEVELS FOR THE QA ORGANIZATION

This item was evaluated in Item I.F.2 above and was determined to be RESOLVED. New requirements were established with changes to the SRP.[11]

ITEM I.F.2(10): CLARIFY REQUIREMENTS FOR MAINTENANCE OF "AS-BUILT" DOCUMENTATION

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

ITEM I.F.2(11): DEFINE ROLE OF QA IN DESIGN AND ANALYSIS ACTIVITIES

This item was evaluated in Item I.F.2 above and was determined to be a LOW priority issue.

REFERENCES

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

308. SECY-82-352, "Assurance of Quality," August 20, 1982.

366. NUREG/CR-2787, "Interim Reliability Evaluation Program: Analysis of the Arkansas Nuclear One - Unit One Nuclear Power Plant," U.S. Nuclear Regulatory Commission, June 1982.

760. NUREG/CR-2802 and Appendices A, B, and C, "Interim Reliability Evaluation program: Analysis of the Browns Ferry, Unit 1, Nuclear Plant," U.S. Nuclear Regulatory Commission, August 1982.

810. NUREG/CR-3085, "Interim Reliability Evaluation Program: Analysis of the Millstone Point Unit 1 Nuclear Power Plant," U.S. Nuclear Regulatory Commission, (Vol. 1) April 1983, (Vol 2) August 1983, (Vol. 3) July 1983, (Vol. 4) July 1983.

811. NUREG/CR-3511, "Interim Reliability Evaluation Program: Analysis of the Calvert Cliffs Unit 1 Nuclear Power Plant," U.S. Nuclear Regulatory Commission, (Vol. 1) May 1984, (Vol 2) October 1984.

812. NUREG/CR-2728, "Interim Reliability Evaluation Program Procedures Guide," U.S. Nuclear Regulatory Commission, March 1983.

1177. NRC Letter to All Holders of Operating Licenses, Applicants for Operating Licenses and Holders of Construction Permits for Power Reactors, "NRC Use of the Terms, 'Important to Safety' and 'Safety Related' (Generic Letter 84-01)," January 5, 1984.

1178. NRC Memorandum and Order CLI-84-9, June 6, 1984.

1179. SECY-85-119, "Issuance of Proposed Rule on the Important-to-Safety Issue," April 5, 1985.

1180. Memorandum for W. Dircks from S. Chilk, "Staff Requirements -- SECY-85-119 - 'Issuance of Proposed Rule on the Important-to-Safety Issue," December 31, 1985.

1181. SECY-86-164, "Proposed Rule on the Important-to-Safety Issue," May 29, 1986.

1182. Memorandum for V. Stello from E. Beckjord, "Resolution of Generic Issue I.F.1, 'Expand QA List,'" January 12, 1989.

TASK I.G: PREOPERATIONAL AND LOW-POWER TESTING

The objectives of this task are as follows: (1) to increase the capability of the shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and off-normal events is conducted. Near-term operating license facilities will be required to develop and implement intensified training exercises during the low-power testing programs; and (2) to review the comprehensiveness of test programs.

ITEM I.G.1: TRAINING REQUIREMENTS

DESCRIPTION

This TMI Action Plan[48] item called for new OLs to conduct a set of low power tests to achieve the objectives of Task I.G. These tests were to be determined on a case-by-case basis.

CONCLUSION

This item was clarified in NUREG-0737[98] and requirements were issued.

ITEM I.G.2: SCOPE OF TEST PROGRAM

DESCRIPTION

Historical Background

The major thrust of TMI Action Plan[48] Task I.G was to use the preoperational and startup test programs as a training exercise for the operating crews. In contrast to this, Item I.G.2 called for a more comprehensive test program to search for anomalies in a plant's response to a transient. This issue was suggested independently by the Kemeny Commission,[175] the Rogovin Commission,[161] the ACRS,[176] and the TMI Operations Team.[177]

Safety Significance

The safety significance of this issue lies in the early discovery of anomalies or unanticipated plant behavior. The TMI-2 accident is the most well-known example, but other less severe examples, such as the core-annulus water level decoupling at Oyster Creek, have taken place.

When a plant responds to a transient in an anomalous or unanticipated manner, the result may be an accident caused directly by the new phenomena, or by the surprise or confusion on the part of the operators. The latter is probably the more likely of the two.

Possible Solution

The nature of the solution to this issue is implicit in its definition - an augmented test program. However, relatively little has been written concerning the nature and extent of this program. NUREG-0660[48] merely called for the NRC to develop a program. Recommendations[177] made by an OIE team investigating TMI-2 are more specific: detailed review of all unscheduled transients during the first year as well as review of the preoperational and startup tests.

In actual fact, there is a spectrum of possible test programs ranging from the current program to programs which would take years. Morever, it may well not be necessary for each plant to perform each test. In addition, there is a large amount of data from operating experience which could supply information.

PRIORITY DETERMINATION

Frequency Estimate

Transients occur at an approximate rate of 10/RY. However, most of these are relatively routine (e.g., turbine trip) and are thus unlikely to produce unpleasant surprises. In any case, existing startup programs should cover them adequately. Therefore, we will focus our attention on transients which are rare, but are nevertheless frequent enough to be considered "anticipated operational occurrences." EPRI NP-801[178] is a report of the transients actually experienced in operating history. Based on judgment, we have selected transients which are candidates for suspicion of anomalous behavior.

PWR Transients	Frequency (RY^{-1})
Hi/Lo Pressurizer Pressure	0.10
Pressurizer Safety or Relief-Valve Opening	0.02
Inadvertent SIS	0.04
Loss of RCS Flow	0.04
Close All MSIVs	0.05
Sudden Opening of Secondary Relief Valves	0.06
Loss of Component Cooling	0.01
Loss of Service Water System	0.01
Total:	0.33

BWR Transients	Frequency (RY^{-1})
Pressure Regulator Fails Open	0.29
Pressure Regulator Fails Closed	0.14
Inadvertent Opening of S/RV	0.20
Trip One Recirculation Pump	0.02
Trip All Recirculation Pumps	0.06
Total:	0.71

Currently, reactor experience totals about 225 BWR-years and 340 PWR-years (565 RY total).[179] Thus, it is estimated that around 270 of the listed transients have occurred. Some of these transients have indeed illustrated the need for corrective measures. Unfortunately, it is not practical to use the computerized data banks to search for "anomalous behavior." Once again we are compelled to use judgment. At least four transients with anomalous response have occurred (Davis-Besse, Three Mile Island, Oyster Creek, Pilgrim) and are widely known. If a more thorough review of operating experience were made, more would be discovered. We estimate that perhaps 10 transients have shown some sort of unanticipated phenomenon. However, the number of interest is the number of phenomena left to be discovered. With about 270 transients of interest already history, anomalous events are not expected to be very common. Moreover, those discoveries which have been made have also led to measures intended to prevent future problems.

Bearing all this in mind, we estimate that anomalous or unanticipated behavior can be expected at a rate of about 5 events in 565 RY (i.e., half the estimated historical rate) or about 10^{-2}/RY. This number is an "educated guess" that the actual number of events that have occurred is higher than the four events listed, but will be lower in the future because this experience has been used to correct these problems.

Consequence Estimate

Most anomalous transients have no consequences in the sense of releasing radioactivity. Based on the experience of TMI (one event in perhaps 10), we will assume that one event in 10 will result in core damage (extensive cladding failure) and one event in 100 will result in a core-melt with a significant release. We will approximate the former with a PWR-9 or BWR-5 Category of event and the latter with a PWR-7 or BWR-4.

We will assume that an augmented startup program will be 50% effective in discovering and correcting problems. The total risk reduction associated with this issue is 2.58×10^4 man-rem, based on 252 man-rem for 36 PWRs and 2.56×10^4 man-rem for 21 BWRs.

Cost Estimate

Industry Cost: As was stated previously, there is a spectrum of possible test programs. We will assume that the test program will average 2 weeks/plant. At $300,000/day for replacement power (which will dominate the cost), this is $4.2M/plant. The 2-week average estimate assumes that not every plant will perform every test. In many cases, the first of a given product line will perform a great deal of testing which will apply to all plants of the same design; or, testing could be shared within a product line by some other plan. Therefore, the total industry cost is $239.4M.

NRC Cost: For NRC cost, we will assume 5 staff-years to develop guidelines and approve generic plans, plus one staff-month of post-test review per plant. With 57 OLs on the docket (36 PWRs and 21 BWRs), this works out to about $1M.

Total Cost: The total industry and NRC cost associated with the possible solution to the issue is $(239.4 + 1)M or approximately $240M.

Value/Impact Assessment

Based on a potential risk reduction of 2.58×10^4 man-rem and an estimated cost of $240M, the value/impact score is given by:

$$S = \frac{2.58 \times 10^4 \text{ man-rem}}{\$240M}$$

$$= 108 \text{ man-rem/\$M}$$

Uncertainties

The frequency estimates used here do not rest upon firm bases. This is not surprising because, like any other program where the goal is discovery, if good bases were available for estimates of effectiveness, the tests would not be necessary. Nevertheless, we can attempt to put bounds on our figures. The frequency of core damage is not likely to be uncertain to more than a factor of 10. If the true frequency were a factor of 10 higher, about 6 core-damaging accidents should have occurred by now. If it were a factor of 10 lower, the TMI-2 accident would have a probability on the order of 0.05.

Howe er, the frequency of core-melt is subject to more uncertainty. We have assumed that the frequency of core-melt is one-tenth of that of core-damage. We will assume that this figure could be either a factor of 5 higher (every second TMI-like event a core-melt) or a factor of 5 lower (one core-melt in 50 core-damage events).

If we assume that the public dose estimates are uncertain to a factor of 5 and the costs to a factor of 5, then S would have a range from 3×10^0 to 4×10^3 man-rem/$M.

Other Considerations

The value/impact score obtained above does not consider the averted costs of cleanup. If such costs ($0.25M/RY) were included, the value/impact score would be significantly higher, but not enough to justify a higher priority.

CONCLUSION

Based on the consideration of the value/impact score and the associated public risk, this item was determined to be a medium priority issue. However, with revisions to SRP[11] Section 14 and the OIE Manual, this issue was RESOLVED and new requirements were established.[654]

REFERENCES

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

161. NUREG/CR-1250, "Three Mile Island: A Report to the Commission and to the Public," U.S. Nuclear Regulatory Commission, January 1980.

175. ZAR-791030-01, "Report of the President's Commission on the Accident at Three Mile Island," J. Kemeny, et. al., November 30, 1979.

176. Memorandum for J. Ahearne from M. Carbon, "Comments on the Pause in Licensing," December 11, 1979.

177. Memorandum for N. Moseley from J. Allan, "Operations Team Recommendations-IE/TMI Unit 2 Investigation," pp. 9, 36, October 16, 1979.

178. EPRI NP-801, "ATWS: A Reappraisal, Part III, Frequency of Anticipated Transients," Electric Power Research Institute, July 1978.

179. NUREG-0020, "Licensed Operating Reactors, Status Summary Report," U.S. Nuclear Regulatory Commission, February 1982.

180. NUREG-0580, "Regulatory Licensing Status Summary Report," U.S. Nuclear Regulatory Commission, June 1982.

654. Memorandum for W. Dircks from H. Thompson, "Closeout of TMI Action Plan Task I.G.2, 'Scope of Test Program,'" October 5, 1984.

TASK II.D: REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES

The objective of this task is to demonstrate by testing and analysis that the relief and safety valves, block valves, and associated piping in the reactor coolant system are qualified for the full range of operating and accident conditions. Anticipated transients without scram (ATWS) may be considered in later phases of the test program. In addition, design changes or modifications will be made that are necessary to provide positive indication of valve position.

ITEM II.D.1: TESTING REQUIREMENTS

DESCRIPTION

This TMI Action Plan[48] item called for applicants and licensees to conduct testing to qualify reactor coolant relief valves, safety valves, block valves, and associated discharge piping for all operating conditions and design basis accidents.

CONCLUSION

This item was RESOLVED, requirements were issued, and MPA F-14 was established by DL for implementation purposes.

ITEM II.D.2: RESEARCH ON RELIEF AND SAFETY VALVE TEST REQUIREMENTS

Historical Background

This TMI Action Plan[48] item specified that RES contract with the Idaho National Engineering Laboratory to: act as a systems integrator to technically monitor and analyze the planned industry valve test and analytical program at EPRI and to collect, analyze, and compare information from foreign tests; develop, improve, or verify available flow discharge and structural response models using the above information; determine the need for a valve-testing program by NRC, with the main focus to be on subcooled and two-phase discharge and on determining operability; and conduct additional tests, as necessary, to assure that the response to the full spectrum of fluid conditions that would be expected to result from anticipated operational occurrences and ATWS events has been adequately characterized. The above work, with the exception of the ATWS events, has been performed in conjunction with Item II.D.1 which was clarified in NUREG-0737.[98]

Safety Significance

The remaining concern under Item II.D.2 with respect to ATWS events is the capability to depressurize the reactor. Coupled with failure of the RPS following a transient, inadequate depressurization could result in rupture of the RCPB producing a LOCA.

Possible Solution

To estimate the public risk associated with ATWS events, it was assumed[64] that a possible solution would be to increase the sizing of the relief and safety valves. This modification was assumed to decrease the likelihood of an ATWS-induced rupture of the RCPB by enhancing the depressurization capability of the system.

PRIORITY DETERMINATION

Assumptions

Using Oconee 3 as representative of PWRs, PNL[64] assumed that the dominant core-melt sequence representative of an ATWS event would involve a Power-Conversion-System (PCS) transient caused by events other than a Loss-of-Offsite-Power (LOOP) and failure of the RPS. The LOCA initiator was assumed to be a RCPB pipe rupture with an equivalent 4 in. diameter. Equipment failures included the containment spray recirculation system and emergency coolant injection and recirculation systems. The containment failure modes were assumed to be similar to other PWR release categories involving RCPB ruptures.

The Grand Gulf reactor was assumed to be representative of BWRs. The dominant core-melt sequence used to model the ATWS event involved transients other than LOOP which require shutdown and a failure to achieve subcriticality. The LOCA initiator was assumed to be a RCPB rupture equivalent to an area of 1 sq.ft. The equipment failure assumed was loss of the RHR system after the LOCA. The containment failure modes were similar to other BWR release categories involving a LOCA and subsequent loss of RHR.

Frequency/Consequence Estimate

Based on the above assumptions, the reductions in core-melt frequencies as a result of modifying the SRVs was calculated to be 3.8×10^{-7}/RY for PWRs and 7.1×10^{-9}/RY for BWRs. The per plant reduction in public risk were calculated to be 0.99 man-rem/RY for PWRs and 0.51 man-rem/RY for BWRs.

Assuming at least one-half of the plants are affected (45 PWRs and 22 BWRs), with an average remaining life of 28.7 years for PWRs and 27.4 years for BWRs, the total public risk reduction is 1,300 man-rem.

Cost Estimate

Industry Cost: Hardware (SRV) modifications are assumed to require approximately 125 man-weeks/plant. At a rate of $2,270/man-week, the per plant labor cost is estimated at $284,000. Equipment is estimated at $100,000/plant. For backfit plants the License Amendment Fee is $4,000. These costs result in a per plant cost of $388,000 for backfit plants, and $384,000 for forward-fit plants. For the forward-fit plants, it is assumed that only half of the plants scheduled to begin operation prior to 1986 will require modifications and, subsequent to that time, the modifications will be incorporated during initial installation. Based on these estimates, the total industry cost is $21M.

NRC Cost: The NRC costs are estimated to be $0.4M for development and $0.3M for implementation. The development cost is assumed to require 2 man-years of NRC effort and 2 man-years of contractor support. The implementation cost to monitor the hardware modifications at the affected plants is assumed to require 2 man-weeks/plant (36 backfit plants, 19 forward-fit plants). Based on these estimates, the total NRC cost is $0.7M.

Value/Impact Assessment

Based on a potential public risk reduction for ATWS events of 760 man-rem and total industry and NRC costs of $21.7M, the value/impact score is:

$$S = \frac{1,300 \text{ man-rem}}{\$21.7M}$$

$$= 60 \text{ man-rem/\$M}$$

CONCLUSION

With the exception of potential ATWS events, Item II.D.2 was integrated into Item II.D.1. The part of Item II.D.2 that involves consideration of ATWS events was given a LOW priority ranking.

ITEM II.D.3: RELIEF AND SAFETY VALVE POSITION INDICATION

DESCRIPTION

This TMI Action Plan[48] item called for all OLs and applicants for OLs to provide the reactor coolant system relief and safety valves with position indication in the control room.

CONCLUSION

This item was clarified in NUREG-0737[98] and requirements were issued.

REFERENCES

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

98. NUREG-0737, "Clarification of TMI Action Plan Requirements," U.S. Nuclear Regulatory Commission, November 1980.

TASK II.E.6: IN SITU TESTING OF VALVES

The objective of this task is to evaluate whether current requirements for valve testing provide adequate assurance of performance under design conditions.

ITEM II.E.6.1: TEST ADEQUACY STUDY

DESCRIPTION

Historical Background

The purpose of this TMI Action Plan[48] item is to establish the adequacy of current requirements for safety-related valve testing. It recommends a study which would result in recommendations for alternate means of verifying performance requirements

Safety Significance

Valve performance is critical to the successful functioning of a large number of the plants' safety systems.

Possible Solution

It could be assumed that a study would be conducted for both PWRs and BWRs and that it could result in recommendations for additional testing and/or maintenance on all safety-related valves. A program to implement the recommendations would then be required at all plants.

PRIORITY DETERMINATION

Assumptions

In an analysis of this issue completed by PNL,[64] it was assumed that all safety-related valves would be affected by the issue resolution. Then, since all the dominant accident sequences (of Oconee and Grand Gulf, the representative plants) involve failures of such valves, the sequences themselves are assumed to be directly affected. It was assumed that the new program would produce a reduction of 5% in the frequencies of the affected accident sequences (those that involve safety-related valves).

Frequency Estimate

It was determined[64] that all accident sequences for Oconee, except the following, involve safety-related valves and are thus assumed to be affected: T_2MLUO, T_2KMO, $T_1(B_3)MLU$, T_1MLUO, and T_3MLUO. For Grand Gulf, the only exception is $T_{23}C$.

For all the affected parameters, the base case frequency was taken as the original value. The adjusted case frequency was then calculated by the 5% reduction. The core-melt frequency reduction was then calculated to be 3×10^{-6}/RY and 10^{-6}/RY for Oconee and Grand Gulf, respectively.

Consequence Estimate

Based on the 5% reduction, the public risk reduction was calculated to be 7.1 man-rem/RY and 7.8 man-rem/RY for Oconee and Grand Gulf, respectively.

The average remaining lives of the 95 affected PWRs and the 49 affected BWRs were calculated to be 28.2 years and 26.2 years, respectively. This results in a potential risk reduction of 1.9×10^4 man-rem for PWRs and 10^4 man-rem for BWRs. Thus, the total risk reduction associated with this issue is approximately 3×10^4 man-rem.

Cost Estimate

Industry Cost: It was estimated that the implementation effort for engineering, etc., would be about 10 man-wk/plant for PWRs and 8 man-wk/plant for BWRs. (The difference is due to the fewer number of affected valves in a BWR.) The cost is then,

PWRs: (10 man-wk/plant)($2,000/man-wk) = $20,000/plant
BWRs: (8 man-wk/plant)($2,000/man-wk) = $16,000/plant

For the 95 PWRs and 49 BWRs, this cost amounts to $2.7M.

The annual industry effort for operations and maintenance was estimated to be 16 man-wk/RY for PWRs and 12 man-wk/RY for BWRs. This results in costs of $16,000/RY for PWRs and $12,000/RY for BWRs. For the 95 PWRs with an average remaining life of 28.2 years, this cost is approximately $42.9M. For the 49 BWRs with an average remaining life of 26.2 years, this cost is approximately $15.4M.

Thus, the total industry cost to implement the possible solution to this issue is $(2.7 + 42.9 + 15.4)M or $61M.

NRC Cost: NRC labor for development of the solution for PWRs is estimated to be 1 man-year. Implementation of the solution is estimated to take 1 man-week/plant. Development of the solution for BWRs is estimated to be 0.5 man-year. Implementation time expended is estimated to be the same as for PWRs. Therefore, the estimated NRC costs are $0.43M.

It was also estimated that NRC labor for periodic review of the issue operation and maintenance would be 1 man-wk/RY for PWRs and 0.5 man-wk/RY for BWRs. This translated into $2,000/RY and $1,000/RY, respectively, for all plants for a cost of $6.7M. Thus, the total NRC cost is $(0.43 + 6.7)M or $7.1M.

Total Cost: The total industry and NRC cost to resolve this issue was estimated to be $(61 + 7.1)M or $68.1M.

Value/Impact Assessment

Based on a potential risk reduction of 3 x 10^4 man-rem and an estimated implementation cost of \$68.1M, the value/impact score is given by:

$$S = \frac{3 \times 10^4 \text{ man-rem}}{\$68.1\text{M}}$$

$$= 440 \text{ man-rem/\$M}$$

Uncertainty

The value/impact score was significantly influenced by the assumption that a 5% frequency reduction could be obtained; this number is highly judgmental.

Other Considerations

(1) Occupational dose would lower (significantly) this value/impact score because the labor required in a radiation zone would be significant. Our estimate of occupational dose due to performing this periodic testing was about 24 man-rem/RY for PWRs and 18 man-rem/RY for BWRs. Over the life of a plant, the overall (total) occupational dose is 8.9 x 10^4 man-rem.

(2) Occupational risk reduction due to accident avoidance was concluded to be small and accident avoidance costs, although large when considered in relation to the other costs, would not significantly change the score.

CONCLUSION

Based on the value/impact score and the additional considerations, this issue was given a medium priority ranking and was later divided into four parts during resolution: (1) pressure isolation valves; (2) check valves; (3) reevaluation of thermal-overload protection provisions of Regulatory Guide 1.106[1215] for MOVs; and (4) in-situ testing of MOVs.

The investigation of alternatives to leak rate testing of pressure isolation valves, including check valves, was integrated into the resolution of Issue 105, "Interfacing Systems LOCA." These alternatives include non-intrusive methods to detect check valve disk position and motion, as well as surveillance of internal parts by various means. Any new issue regarding testing of check valves that may be identified in the future will be prioritized as a new generic issue. The results of the staff's study of MOV thermal overload protection were published in NUREG-1296.[1216] The staff concluded that, although misinterpreted by the industry at times, the guidelines in Regulatory Guide 1.106[1215] were adequate. Several suggestions for improving MOV thermal overload protection were outlined in NUREG-1296.[1216] In addition, letters were sent to the pertinent IEEE and ASME subcommittees encouraging the development of standards for MOV thermal overload protection. In-situ testing and surveillance of check valves is being addressed by an industry effort; in-situ testing of MOVs was resolved with the issuance of Generic Letter 89-10.[1217] Thus, this issue was RESOLVED and requirements were established.[1218]

REFERENCES

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

1215. Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves," U.S. Nuclear Regulatory Commission, November 1975 (Rev. 1) March 1977.

1216. NUREG-1296, "Thermal Overload Protection for Electric Motors on Safety-Related Motor-Operated Valves - Generic Issue II.E.6.1," U.S. Nuclear Regulatory Commission, June 1988.

1217. NRC Letter to All Licensees of Operating Power Plants and Holders of Construction Permits for Nuclear Power Plants, "Safety-Related Motor-Operated Valve Testing and Surveillance (Generic Letter No. 89-10) - 10 CFR 50.54(f)," June 28, 1989.

1218. Memorandum for V. Stello from E. Beckjord, "Close-out of Generic Issue II.E.6.1, 'In Situ Testing of Valves.'" June 30, 1989.

TASK II.F: INSTRUMENTATION AND CONTROLS

The objective of this task is to provide instrumentation to monitor plant variables and systems during and following an accident. Indications of plant variables and status of systems important to safety are required by the plant operator (licensee) during accident situations to: (1) provide information needed to permit the operator to take preplanned manual actions to accomplish safe plant shutdown; (2) determine whether the reactor trip, engineered safety features systems, an manually-initiated systems are performing their intended functions (i.e., reactivity control, core cooling, maintaining reactor coolant system integrity, and maintaining containment integrity); (3) provide information to the operator that will enable him to determine the potential for a breach of the barriers to radioactivity release (i.e., fuel cladding, reactor coolant pressure boundary, and containment) and if a barrier has been breached; (4) furnish data for deciding on the need to take unplanned action if an automatic or manually-initiated safety system is not functioning properly or the plant is not responding properly to the safety systems in operation; (5) allow for early indication of the need to initiate action necessary to protect the public and for an estimate of the magnitude of the impending threat; and (6) improve requirements and guidance for classifying nuclear power plant instrumentation control and electrical equipment important to safety.

ITEM II.F.1: ADDITIONAL ACCIDENT MONITORING INSTRUMENTATION

This item was clarified in NUREG-0737,[98] requirements were issued, and MPAs F-20, F-21, F-22, F-23, F-24, and F-25 were established by DL for implementation purposes.

ITEM II.F.2: IDENTIFICATION OF AND RECOVERY FROM CONDITIONS LEADING TO INADEQUATE CORE COOLING

This item was clarified in NUREG-0737,[98] requirements were issued, and MPA F-26 was established by DL for implementation purposes.

ITEM II.F.3: INSTRUMENTS FOR MONITORING ACCIDENT CONDITIONS

DESCRIPTION

After the TMI-2 event, Task II.F of the TMI Action Plan[48] addressed several concerns regarding the availability and adequacy of instrumentation to monitor plant variables and systems during and following an accident.

Prior to the TMI-2 event, Regulatory Guide 1.97,[55] "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," (August 1977) had been used as guidance during licensing reviews. Item II.F.3 called for this regulatory guide to be updated to include the TMI-2 concerns.

Revision 2 of Regulatory Guide 1.97[55] was published in December of 1980 and implementation is being carried out as discussed in SECY-82-111[151] and a letter[376] issued to all licensees of operating reactors.

CONCLUSION

This item was RESOLVED and new requirements were established.

ITEM II.F.4: STUDY OF CONTROL AND PROTECTIVE ACTION DESIGN REQUIREMENTS

DESCRIPTION

Historical Background

After the TMI-2 event, the Special Inquiry Group made recommendations[161] for the staff to study three items in the area of control and protection systems. These were: (1) automatic reactor protection actions should be derived, to the degree possible, from independent process variables; (2) automatic actions through coincidence of independent process variables should be limited, to the degree possible, for non-reactor protection functions; (3) control circuit components should be designed and periodically tested at expected degraded power supply conditions to ensure that they are capable of performing their intended function.

Safety Significance

The report[161] concluded that improvements in these areas may help prevent specific occurrences which were noted upon evaluation of the TMI-2 event.

Possible Solutions

This TMI Action Plan[48] item addresses the performance of a study that could indicate potential deficiencies and identify possible fixes which could be incorporated as design criteria in the SRP.[11] Industry would then be required to meet these criteria.

PRIORITY DETERMINATION

We have not attempted to estimate a value/impact score for this issue. It would appear that the non-specific nature of these recommendations (i.e., use of words like "to the degree possible") would require a large amount of additional study prior to defining any specific implementation requirements. Therefore, we could not make an estimate of either potential risk reduction or costs. The following considerations were taken into account.

(1) Our understanding of the first criterion has led us to believe that, to a large degree, it is typically addressed by existing protection systems. The use of a number of different plant parameters to initiate the protection system is an indication of the application of this criteria. We grant that there may be instances in different plant designs where, for certain events, these criteria have not been adequately addressed; however, we tend to believe that these would be isolated instances. Furthermore, the proposed ATWS rule which included NUREG-0460[201] requirements will address

monitoring of independent process variables. As another consideration, we believe that protection system design requirements will undergo another review as a result of preparation of a Regulatory Guide to endorse industry standard IEEE 603-1977.[200]

(2) The second criterion addresses non-protection systems. At present the staff does not have detailed design criteria for these systems (typically referred to as "control systems") in the SRP.[11] We believe that if any criteria are to be included, they will be the result of a comprehensive program such as the existing program addressing USI A-47, "Safety Implications of Control Systems."

(3) One part of the third criterion is addressed in SRP[11] Section 3.11, "Environmental Qualification of Equipment." Specifically, safety-related components are designed for performance at varying power supply conditions. Typically, they are initially tested to these conditions as part of their qualification program. The other part of the third criterion is not presently required. Under conditions with offsite power feeding all plant components, it could be postulated that redundant components could experience some degraded power supply conditions; however, this concern was addressed through various plant fixes as part of their degraded grid analysis. Under conditions with onsite power feeding the components, the independence of the systems would prevent redundant components from experiencing degraded power.

CONCLUSION

Based on the considerations listed above, this issue was placed in the DROP category.

ITEM II.F.5: CLASSIFICATION OF INSTRUMENTATION, CONTROL, AND ELECTRICAL EQUIPMENT

DESCRIPTION

Historical Background

After TMI, the staff recommended[48] that the present method of classifying instrumentation, control, and electrical equipment needed revision to allow graded criteria which would more closely correspond to the equipment's importance to safety.

Safety Significance

Such a grading could place emphasis on improvements in the non-class 1E systems which could affect core-melt frequency. It could also allow more design flexibility and result in potentially more cost-effective electrical, instrumentation, and control system designs.

Possible Solution

It was recommended that the NRC, in conjunction with IEEE, develop a standard which would provide a classification approach based on the level of importance to safety of equipment. The standard would then be endorsed by a Regulatory

Guide. Utility conformance to important criteria such as redundancy, reliability, etc. for selected systems would be mandated.

PRIORITY DETERMINATION

Assumptions

A program to classify and upgrade non-1E instrumentation, controls, and electrical systems is assumed to improve balance-of-plant system reliability and thus reduce transient frequencies. Based on EPRI transient data,[307] a number of transient categories and frequencies of interest were identified. In a PNL assessment[64] of this issue, it was assumed that 50% of all these transients were attributable to instrumentation, control, and electrical system failures. Then it was assumed that resolution of this issue would result in about a 10% reduction in such failures.

Frequency/Consequence Estimate

The reduction assumed above translates into about a 6% reduction in transients (other than loss of offsite power) for PWRs and a 4% reduction in transients for BWRs. Therefore, the 6% reduction was divided between the T_2 and T_3 transients for PWRs in the Oconee risk equations. The 4% reduction was applied to the T_{23} transients for BWRs in the Grand Gulf equations. This resulted in reductions in core-melt frequency of 2.1×10^{-6}/RY for PWRs and 9×10^{-7}/RY for BWRs. This translates (assuming a population density at 340 people/square-mile) to a per plant reduction in public risk of 5.6 man-rem/RY for PWRs and 7 man-rem/RY for BWRs. Assuming 90 PWRs with an average remaining life of 28.8 yrs and 44 BWRs with an average remaining life of 27.4 yrs, this results in a total public risk reduction of 23,000 man-rem.

Cost Estimate

An estimate of costs for implementing improved non-1E systems was based on the installation cost ($1M) of a safety parameter display system (SPDS) at Yankee Rowe. The SPDS is considered a non-1E system which includes certain design features beyond those of a typical non-1E system. It was assumed that classification and upgrading of all remaining non-1E systems will represent a similar cost of $1M per plant, divided evenly between equipment costs and manpower costs for backfit plants. Forward-fit plants should only require additional equipment costs. Total industry cost would then be (based on 47 backfit and 43 forward-fit PWRs and 24 backfit and 20 forward-fit BWRs) about $100M.

Since the IEEE Trial Use Guide, IEEE-827[233] has been released, the NRC cost for development is considered minimal (i.e., on the order of 0.5 man-year). We believe that the NRC cost for support of the resolution would potentially be significant. We assumed 1 man-year/plant. This results in NRC support cost of $13.4M.

Value/Impact Assessment

Based on a total risk reduction of 23,000 man-rem, the value/impact score is given by:

$$S = \frac{23{,}000 \text{ man-rem}}{\$(13.4 + 100)M}$$

$$= 200 \text{ man-rem/\$M}.$$

Uncertainties

(1) The estimates of the transient frequency reductions are subject to many assumptions which themselves are uncertain.

(2) Cost estimates are extremely hard to make without a clearer fix in mind.

(3) NRC review time would also vary based on the actual fix involved.

Other Considerations

(1) A significant industry cost saving (which would outweigh the industry cost) could be calculated based on a saving in plant outage time due to improved non-1E system reliability. For example, if it were assumed that a reduction of non-loss of offsite power transients would occur (7 to 6.58/RY), then assuming one day of power generation lost per transient, this reduces the unscheduled outages by 0.42 day/RY. Based on a replacement power cost of $3000,000/day, the cost savings would be (0.42 day/RY) ($3000,000/day) = $130,000/RY. For 134 plants with a remaining lifetime of 30 years, the total cost savings would be (134 plants)(30 years) ($130,000/RY) = $523M.

(2) IEEE-827,[233] Trial Use Guide, "A Method for Determining Requirements for Instrumentation, Control and Electrical Systems Important to Safety," has been issued.

(3) RES was in the process of developing a draft regulatory guide for the classification of systems important to safety which would provide for a Class 2E instrumentation, control, and electrical power system and equipment. This effort was proceeding independently of the IEEE/ANS efforts.

CONCLUSION

Based on the favorable value/impact score, the effort expended up to the time of the above analysis, and the potential risk reduction and cost saving, this issue was given a medium priority ranking. However, after further evaluation, it was reclassified as a Licensing Issue based on the continuation of the staff's support of the IEEE efforts to develop a standard to define requirements for equipment and systems that are not safety-related, but are sufficiently important to safety to warrant special consideration.[1105]

The Draft Trial Use Guide (IEEE-827)[233] was developed by IEEE but was never published; the project was withdrawn in 1983. Under a separate activity, BNL, under contract with the NRC, attempted to develop a methodology to address the classification issue. In both instances, these activities were terminated due to a lack of agreement on the scope and content of the issue.

In 1989, the IEEE/NPEC Working Group SC 6.2 continued to develop a Position Paper on this issue that will only address the possible benefits for establishing a graduated classification program and will provide a list of attributes that would be prudent to incorporate in such a program. However, the Position Paper will not establish any specific guidelines for an acceptable program.

Based on the lack of new plants being constructed, the industry's reluctance to change their existing classification documentation, and the previous efforts both by the NRC staff and the industry to develop a classification methodology, the staff concluded that no additional NRC action should be taken. Thus, the issue has been resolved.[1187]

REFERENCES

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

48. NUREG-0660 "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980.

55. Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," U.S. Nuclear Regulatory Commission.

98. NUREG-0737, "Clarification of TMI Action Plan Requirements," U.S. Nuclear Regulatory Commission, November 1980.

151. SECY-82-111, "Requirements for Emergency Response Capability," March 11, 1982.

161. NUREG/CR-1250, "Three Mile Island: A Report to the Commission and to the Public," U.S. Nuclear Regulatory Commission, January 1980.

200. IEEE 603-1977, "Trial-Use Standard Criteria for Safety Systems for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

201. NUREG-0460, "Anticipated Transients without SCRAM for Light Water Reactors," U.S. Nuclear Regulatory Commission, April 1978.

233. IEEE P-827, "A Method for Determining Requirements for Instrumentation Control and Electrical Systems and Equipment Important to Safety," Institute of Electrical and Electronics Engineers.

307. EPRI NP-2230, "ATWS: A Reappraisal, Part 3," Electric Power Research Institute, 1982.

376. NRC Letter to All Licensees of Operating Reactors, Applicants for Operating Licenses, and Holders of Construction Permits, "Supplement 1 to NUREG-0737, Requirements for Emergency Response Capability (Generic Letter No. 82-33)," December 17, 1982.

1105. Memorandum for T. Speis from G. Arlotto, "Generic Issues Program," January 14, 1988.

1187. Memorandum for V. Stello from E. Beckjord, "Closeout of Generic Issue II.F.5, 'Classification of Instrumentation, Control and Electrical Equipment,'" May 5, 1989.

ITEM A-48: HYDROGEN CONTROL MEASURES AND EFFECTS OF HYDROGEN BURNS ON SAFETY EQUIPMENT

DESCRIPTION

Following a LOCA in an LWR, combustible gases, principally hydrogen, may accumulate inside the primary reactor containment as a result of: (1) metal-water reaction involving the fuel element cladding; (2) the radiolytic decomposition of the water in the reactor core and the containment sump; (3) the corrosion of certain construction materials by the spray solution; and (4) any synergistic chemical, thermal and radiolytic effects of post-accident environmental conditions on containment protective coatings and electric cable insulation. Although hydrogen control measures in connection with a design basis LOCA had been required by 10 CFR 50.44 well before the TMI-2 accident, metal-water reactions generated hydrogen during the accident that were in excess of the amounts specified in 10 CFR 50.44. As a result, it became apparent that additional hydrogen control and mitigation systems would have to be considered in power reactors with small containment structures. This concern was first raised in NUREG-0578[57] and later in TMI Action Plan[48] Item II.B.7. The issue was declared a USI in February 1981 and published in NUREG-0705.[44]

A detailed action plan for resolving the issue was published in NUREG-0649, Rev. 1,[1061] and was limited to near-term rulemaking efforts which included: (1) the BWR Mark I and Mark II containments hydrogen inerting rule; (2) the ice condenser/Mark III containment hydrogen control rule; and (3) the near-term construction permit/manufacturing license (CP/ML) rule. The CP/ML rule specified licensing requirements for pending CP and ML applications. The rule requiring inerting of BWR Mark I and Mark II containments as a method for hydrogen control was published in December 1981.[1225] The BWR Mark I and Mark II containments have operated for a number of years with an inerted atmosphere (by addition of an inert gas, such as nitrogen) which effectively precludes combustion of any hydrogen generated. USI A-48 has been fully implemented at BWR plants with Mark I and Mark II containments.

The rule for BWRs with Mark III containments and PWRs with ice condenser containments was published in January 1985.[1226] This rule required that the affected plants be provided with a means for controlling the quantity of hydrogen produced by a 75% fuel-cladding metal-water reaction, but did not specify the control method. In addition to the promulgation of rules on hydrogen control, the action plan for USI A-48 provided for plant-specific reviews of lead plants for reactors with Mark III and ice condenser containments.

Concurrent with the development of regulations, both the NRC and the industry have conducted extensive research programs since early 1980 on hydrogen igniter systems and effects of hydrogen combustion on safety-related equipment. A number of research programs were started to investigate the control of large quantities of hydrogen in reactors with small volume containments. The staff has also sponsored a peer review of the hydrogen research programs by the National Research Council under the auspices of the

National Academy of Sciences (NAS). The NAS report, "Technical Aspects of Hydrogen Control and Combustion in Severe Light-Water Reactor Accidents," published in 1987 presents findings on the hydrogen research by both industry and the NRC.[1227] The committee concluded that, for most accident scenarios, current regulatory requirements make it highly unlikely that hydrogen detonation would be the cause of containment failure. It was also concluded that inerting is adequate for reactors with Mark I and Mark II containments and that igniters are a reasonable way to reduce the probability of hydrogen detonation in medium volume containments (BWR Mark III and PWR ice condenser).

Large dry PWR containments were excluded from USI A-48 because they have a greater ability to accommodate the large quantities of hydrogen associated with a recoverable degraded core accident than the smaller MARK I, II, III and ice condenser containments. Most dry containments have about two million or more cubic feet of net free volume and have a design pressure which ranges from about 45 to 60 psi. Analyses which were performed to determine the pressure in a dry containment resulting from the combustion of hydrogen corresponding to a 75% metal-water reaction following onset of a degraded core accident and while the containment was still near its peak pressure, indicated that the peak total containment pressure was below the failure pressure. Furthermore, analyses indicated that essential equipment would function during and after a large deflagration in a dry containment. This conclusion was supported by the TMI-2 experience.

CONCLUSION

In December 1984, the staff concluded that rulemaking with regard to hydrogen control for LWRs with large, dry containments could be safely deferred due to the inherent capability of these containments to accommodate large quantities of hydrogen. This concern is covered under Issue 121. In the staff's plans for resolving Issue 121, any recommendations for further modifications to 10 CFR 50.44 related to LWRs with large, dry containments will be provided at the conclusion of ongoing research. In April 1989, SECY-89-122[1227] was forwarded to the Commission documenting the results of the staff's efforts in resolving USI A-48. Thus, this issue was RESOLVED and new requirements were established.

REFERENCES

44. NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plant Stations," U.S. Nuclear Regulatory Commission, March 1981.

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

57. NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," U.S. Nuclear Regulatory Commission, July 1979.

1061. NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants," U.S. Nuclear Regulatory Commission, February 1980, (Revision 1) September 1984.

1225. Federal Register Notice 46 FR 58484, "10 CFR Part 50, Interim Requirements Related to Hydrogen Control," December 2, 1981.

1226. Federal Register Notice 50 FR 3498, "10 CFR Part 50, Hydrogen Control Requirements," January 25, 1985.

1227. SECY-89-122, "Resolution of Unresolved Safety Issue (USI) A-48, 'Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment,'" April 19, 1989.

ITEM B-31: DAM FAILURE MODEL

DESCRIPTION

Historical Background

This issue, as originally stated in 1978,[3] addressed the unavailability (at that time) of a suitable model to predict the erosion rates and, therefore, the flood hydrographs at nuclear power plant sites resulting from the gradual failure of earthen embankment dams. In the absence of such an analytical model, the NRC staff was forced to postulate the instantaneous and complete failure of dams as the basis for flood hydrograph prediction.

The original proposed resolution of this issue was for the staff to develop a model and to validate it using existing dam failure data. This model, when developed, would provide a consistent approach to the required analyses at all riverine sites and would potentially reduce staff time dedicated to the development and review of analytical methods for individual plant sites.[1123]

Since this issue was raised, significant progress has been made in the development and validation of models for gradual failures of earthen dams (References 1124, 1125, 1126, 1127, 1128). Several models have been developed, coded, and the results compared against actual dam failure data. In addition, a 1983 study sponsored by the NRC applied available models to the assessment of flood risk at the Haddam Neck plant. The results of the Haddam Neck study indicated that such models can be used judiciously to guide design on regulatory decisions.[1125]

Safety Significance

Analysis prepared by PNL[1123] indicates no direct safety significance associated with this issue; instead, it involves the development and application of a standardized analytical methodology to an element of the licensing process.

Possible Solution

The proposed resolution to this issue, as originally stated in 1978, was for the NRC to proceed with development of an analytical model, or nomograph, to predict erosion rates and patterns of failure for an earthen embankment for a given initiating mode.[3] Since that time, the state-of-the-art for modeling of the gradual failure of earthen dams has advanced considerably. Efforts undertaken in the late 1970s and early 1980s by the National Weather Service (NWS), the U.S. Army Corps of Engineers Hydrologic Engineering Center (HEC), the Soil Conservation Service (SCS), and others have resulted in the availability of several well-documented computer models. In particular, the NWS-DAMBRK and the HEC-1 Dam Safety Models have been evaluated against actual flood hydrographs in recent studies and both have been used to analyze the flooding risks at a nuclear power plant site. Results of these and other studies indicate that the NWS-DAMBRK model, at least at present, outperforms other models in the simulation of downstream flood profiles.

The resolution of this issue, therefore, remains only for the NRC to assess and apply the available models, including recent progress in two-dimensional solutions, to the classical St. Venant equations (other models are based on one-dimensional solutions) and to assure that the selected model or models are optimal for NRC applications.

CONCLUSION

Public and occupational risks are not expected to be affected by resolution of this issue. The proposed resolution was for the NRC to proceed with development and validation of a suitable dam break model. As documented above, models are available so that the NRC development cost originally estimated by PNL[64] to be $18,200 is eliminated. Generic endorsement of an existing model, for instance DAMBRK, is estimated to pose a potential for a very modest combined savings to the NRC and the industry (~$50,000 total), primarily because of the very limited number of plants, perhaps 4 or 5, which might desire to use the model in their licensing evaluation.

The primary significance of this issue is in the review of power plant construction requirements that takes place during the plant construction phase (construction permit and pre-operating license review). Existing plants may require preparation of updated flood protection analyses. This would occur especially in cases where new dams or other water impoundments which may affect existing plants have been created since the original licensing of these plants. Also, some early plants may not have sophisticated flood protection design analyses, so review and updating of flood hazards may be appropriate. Therefore, although presently not of major significance, this issue could become more important in the context of license renewals.

This issue addresses the analytical methodology for determining plant site flooding potential and improving the effectiveness of the review of license applications; it does not address the occurrence or frequency of specific safety-related plant events. Therefore, it is considered to be a Licensing Issue. Based on the fact that adequate models have been developed to analyze earthen dam failures, it is recommended that this issue be dropped from further consideration.

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ISSUE 15: RADIATION EFFECTS ON REACTOR VESSEL SUPPORTS

DESCRIPTION

Historical Background

This issue addresses the potential problem of radiation embrittlement of reactor vessel support structures (RVSS). It was originally identified as a Candidate USI in NUREG-0705[44] where it was recommended for further study before a judgment was made on its designation as a USI. In a prioritization of the issue in November 1983, it was concluded that the ORE associated with resolving the issue far outweighed the potential decrease in public risk. As a result, the issue was assigned a low priority until additional data on the problem became available that would warrant a reevaluation of the issue. In April 1988, data developed by ORNL[1121, 1122] suggested that the potential embrittlement of the RVSS, as a result of neutron irradiation damage, could be significantly greater than was previously anticipated. Based on this new information, RES/MEB requested a reevaluation of the issue in September 1988.[1120]

Neutron damage of structural materials causes embrittlement that may increase the potential for propagation of flaws that might exist in the materials. The potential for brittle fracture of these materials is typically measured in terms of the material's nil ductility transition temperature (NDTT), which is the lowest temperature at which the material would not be susceptible to failure by brittle fracture. As long as the operating environment in which the materials are used has a higher temperature than the materials' NDTT, no failure by brittle fracture would be expected. Many materials, when subjected to neutron irradiation, experience an upward shift in the NDTT, i.e., they become more susceptible to brittle fracture at the operating temperatures of interest. This effect is accounted for in the design and fabrication of RVSS. However, the ORNL research indicated that the upward shift in NDTT with increased exposure to neutron irradiation has been underestimated. The loss in fracture toughness may result in failure of the RVSS and consequent movement of the reactor vessel, given the occurrence of a transient stress or shock such as would be experienced in an earthquake.

ORNL surveyed RVSS designs at LWRs and categorized each plant into one of five categories or types of RVSS: (1) skirt; (2) long-column; (3) shield-tank; (4) short-column; and (5) suspension. Skirt type supports are located away from the core with a large volume of intervening metal and water. Radiation embrittlement of skirt type RVSS is not anticipated. Long-column type supports are located in a zone of potentially high neutron fluence and are thus susceptible to radiation damage. Similarly, shield-tank supports are also located in a potentially high radiation damage zone. Short-column type supports include several subcategories that are located in various regions relative to the reactor core. Thus, they appear to have a wide variability in susceptibility to radiation damage. Many plants with this type of support have special designs for heat dissipation, including natural convection, forced convection, and water/cooling-coil designs. The fifth category, suspension supports, are employed at only one plant and, although these supports are located in a region of potentially high irradiation damage, the temperature may be high enough to preclude brittle fracture. However, for this analysis, plants employing the long-column, shield-tank, short-column, and suspension type supports are assumed to be susceptible to irradiation damage.

Safety Significance

A large seismic event can cause failure of auxiliary piping which can result in an embrittled RVSS to fracture thereby allowing the reactor vessel to move. Such movement can then worsen the LOCA from the rupture of auxiliary piping by rupturing other piping attached to the primary coolant loop and instrument tubing attached to the bottom head of the reactor vessel.

Possible Solutions

The proposed resolution for some plants involves the application of local heaters and insulation for the RVSS to maintain operating temperatures well above the NDTT of the potentially embrittled support. This resolution would only involve those plants that employ long-column and shield-tank supports. Short-column and suspension supports are in a higher temperature environment and thus heaters are not necessary to maintain the temperatures above the NDTT. However, minor design and equipment changes would be needed to control the amount of heat dissipation applied to the short-column and suspension supports to ensure the NDTT of the structural materials do not exceed the environmental temperature. In all cases, appropriate safeguards must be installed to prevent overheating of the concrete around and in contact with the supports.

PRIORITY DETERMINATION

Assumptions

The number of potentially susceptible plants (78) was determined from the results of the ORNL survey and are summarized below:

		Number of Affected Plants	
Plant Type	RVSS Type	Operating	Under Construction
PWR	Short-column	45	13
	Long-column	10	1
	Shield-tank	8	0
	Sub-Total.	63	14
BWR	Suspension	1	0
	Total:	64	14

The ORNL report also provided the basis for estimates of the length of time a plant could potentially operate in a vulnerable condition, i.e., with embrittled reactor vessel supports. The radiation embrittlement of RVSS materials from two operating LWRs (Turkey Point and Trojan) were investigated and data on the change in NDTT over time were developed. The approximate time at which the RVSS material is believed to become susceptible to brittle fracture is 23 years after the reactor has begun full power operation. Therefore, the potential susceptibility of the RVSS to brittle fracture exists for 7 years at the end of a reactor's lifetime, assuming an average operating lifetime of 30 years. Data from the Oconee 3 and Grand Gulf 1 RSSMAP studies were used in this analysis to determine the estimated risk for PWRs and BWRs, respectively.

Frequency Estimate

The assumed accident scenario is occurrence of a seismic event of sufficient magnitude to case fracture of an embrittled RVSS, subsequent movement of the reactor vessel, and a corresponding LOCA as attached piping ruptures. The analogous accident sequences are those involving LOCA initiators S_1, S_2, and S_3 for Oconee (different initiator frequencies for three pipe diameters) and S for Grand Gulf. These are the corresponding LOCA initiators for pipe ruptures. However, this issue is concerned with only seismically-induced pipe ruptures, which were not addressed in the original Oconee and Grand Gulf studies. As a result, seismically-induced LOCAs are defined here and incorporated into the base case.

The base-case frequencies of seismically-induced LOCA initiators SS_1, SS_2, SS_3, and SS are assumed to be equal, i.e., the conditional probabilities of fracturing different sizes of pipe, given an earthquake, are assumed to be equal. Their base-case frequencies are estimated as follows:

$$f(SS_1) = f(SS_2) = f(SS_3) = f(S) = f(PGA \geq 0.2g) \times p(NDTT) \times p(PR)$$

where $f(PGA \geq 0.2g)$ = frequency of a seismic event with peak ground acceleration greater than or equal to 0.2g; frequency = 7×10^{-4}/yr.[16]

p(NDTT) = conditional probability that a RVSS is susceptible to radiation damage and fails as a result of reactor vessel movement (this value is derived below).

p(PR) = conditional probability of pipe rupture given movement of the reactor vessel [assumed to be accounted for in estimate of p(NDTT); effectively 1.0 for pipes of all diameters].

The conditional probability of failure of an embrittled RVSS as a result of a seismic event [p(NDTT)] is a function of the NDTT at the time the seismic event occurs, the number and size of preexisting flaws in the support material, and the safety factor built into the design of the supports and selection of the material. As discussed above, the RVSS materials at some plants may exceed operating temperatures during the last 7 years of reactor operation. Assuming that this occurs, the safety factor built into the RVSS may not exceed 1 whereas, using previous predictions of radiation damage, this safety factor may be as much as 20. Using a correlation[1123] between safety factor and failure probability, PNL determined that the conditional probability of failure leading to reactor core damage for a safety factor of 1 is 0.5. Using this value, the frequency of seismically-induced LOCAs is:

$$f(SS_1) = f(SS_2) = f(SS_3) = f(S) = (7 \times 10^{-4}/RY)(0.5)(1) = 3.5 \times 10^{-4}/RY$$

PNL derived the base case frequencies by substituting the above frequency of the seismically-induced initiators into the minimal cut sets given in NUREG/CR-2800.[64] The results are as follows:

Oconee

SS_3H - γ (PWR-3) = 1.4×10^{-6}/RY
β (PWR-5) = 2.0×10^{-8}/RY
ε (PWR-7) = 1.4×10^{-6}/RY

SS_1D - α (PWR-1) = 2.4×10^{-7}/RY
γ (PWR-3) = 4.8×10^{-6}/RY
β (PWR-5) = 1.8×10^{-7}/RY
ε (PWR-7) = 1.9×10^{-5}/RY

SS_3FH - γ (PWR-2) = 6.0×10^{-7}/RY
β (PWR-4) = 8.8×10^{-9}/RY
ε (PWR-6) = 6.0×10^{-7}/RY

SS_2FH - α (PWR-1) = 1.1×10^{-8}/RY
β (PWR-4) = 8.0×10^{-9}/RY
ε (PWR-6) = 8.8×10^{-7}/RY

SS_2D - α (PWR-1) = 1.8×10^{-8}/RY
γ (PWR-3) = 3.6×10^{-7}/RY
β (PWR-5) = 1.3×10^{-8}/RY
ε (PWR-7) = 1.4×10^{-6}/RY

SS_3D - γ (PWR-3) = 1.9×10^{-7}/RY
β (PWR-5) = 2.7×10^{-9}/RY
ε (PWR-7) = 1.9×10^{-7}/RY

Grand Gulf

S_1 - α (BWR-1) = 1.2×10^{-8}/RY
δ (BWR-2) = 1.2×10^{-6}/RY

Summing the base case frequencies for the affected release categories, we get the following:

Oconee

PWR-1 = 2.7×10^{-7}/RY
PWR-2 = 6.0×10^{-7}/RY
PWR-3 = 6.8×10^{-6}/RY
PWR-4 = 1.7×10^{-8}/RY
PWR-5 = 2.2×10^{-7}/RY
PWR-6 = 1.5×10^{-6}/RY
PWR-7 = 2.2×10^{-5}/RY

Grand Gulf

BWR-1 = 1.2×10^{-8}/RY
BWR-2 = 1.2×10^{-6}/RY

Based on the above data, the base case affected core-melt frequency is 3.1×10^{-5}/RY for PWRs and 1.2×10^{-6}/RY for BWRs.

The possible solutions were assumed to eliminate the potential for radiation embrittlement of RVSS materials. Thus, the adjusted case core-melt frequency is essentially zero and the potential reduction in core-melt frequency is 3.1×10^{-5}/RY for PWRs and 1.2×10^{-6}/RY for BWRs.

Consequence Estimate

In order to obtain the consequences associated with this issue, the CRAC Code[64] was used. An average population density of 340 persons per square mile was assumed (the average for U.S. domestic sites) from an exclusion area one-half mile about the reactor out to a 50-mile radius. A typical midwest site meteorology was also assumed. Based on these assumptions, the risk for each Release Category is stated in Appendix D of NUREG/CR-2800.[64] Using the frequency estimates derived above, the total estimated risk from the base case is 41.6 man-rem/RY from PWRs and 8.6 man-rem/RY for BWRS. Since the possible solutions are assumed to eliminate the potential for radiation embrittlement of RVSS materials, the adjusted case risk is essentially zero. The risk reduction associated with this issue is as follows:

PWRs: (41.6 man-rem/RY)(77 reactors)(7 years)
= 22,400 man-rem

BWRs: (8.6 man-rem/RY)(1 reactor)(7 years)
= 60 man-rem

Therefore, the total potential risk reduction is 2.24×10^4 man-rem.

Cost Estimate

Industry Cost: At operating plants, the solution consists of controlling the temperature of the RVSS, either through application of local heaters and insulation or through controlling cooling systems that are already in place, to ensure that the temperatures of the structural materials do not fall below the materials' NDTT after irradiation embrittlement. At future plants, the use of nonsusceptible material is the proposed resolution. Since this can be accommodated during the design and construction stages of a plant, no additional costs are foreseen beyond those normally incurred during design and construction.

Affected backfit plants are assumed to implement the resolution after about ten years of reactor operation. It is further assumed that only plants with long-column and shield-tank type supports will install and operate local heaters and insulation on their RVSS. The plants with suspension and short-column type supports are assumed to implement measures to control or limit cooling of the RVSS. Affected forward-fit plants will implement the solution before fuel is loaded into the core. The following is a break-down of the solutions at the 78 affected plants:

PWRs:	(1) Backfit	
	Heaters	18
	Cooling Control	45
	(2) Forward-fit	14
BWRs:	Backfit (cooling)	1

For plants with long-column and shield-tank type supports, it is assumed that heaters will be attached to four reactor vessel support columns and that mounting hardware, metal-sheathed heating cables, switchgear, transformers, and a power controller will be installed. It is also assumed that the equipment will be installed during scheduled reactor outages. Therefore, no additional replacement power costs would be necessary. It is further assumed that access to the reactor cavity is possible for heater installation. PNL estimated the equipment cost to be $52,000/plant; labor associated with installation of this equipment was estimated to be 105 man-weeks/plant. At a cost $2,270/man-week, the installation cost for heaters will be (105 man-week/plant)($2,270/man-week)=$245,000/plant. An additional cost of $26,000/plant is estimated for a Class V amendment. Therefore, the total implementation cost for those plants that will use heaters is $320,000/plant.

For plants with short-column and suspension type supports that will utilize cooling methods, it is assumed that equipment and labor requirements are 10% of that estimated for application of local heaters and insulation. In this case, PNL estimated the equipment cost to be $5,200/plant; labor associated with installation of this equipment was estimated to be 10.5 man-weeks/plant. At a cost of $2,270/man-week, the installation cost for cooling will be (10.5 man-weeks/plant)($2,270/man-week) = $25,000/plant. The Class V licence amendment fee of $26,000/plant will also be applicable. Therefore, the total implementation cost for those plants that will use cooling is $56,000/plant.

Therefore, the total industry implementation cost is given by:
(18 plants)($320,000/plant) + (46 plants)($56,000/plant) = $8.34M.

PNL calculated that operation and maintenance costs will be \$130,000/RY for those plants that use heaters and \$7,100/RY for those that use cooling. Therefore, the total operation and maintenance cost over the 7-year vulnerability period for the affected reactors is given by:

(18 plants)(7 years)(\$130,000/RY) + (46 plants)(7 years)(\$7,100/RY) = \$18.7M.

The total industry cost for implementation, operation, and maintenance of the possible solutions is \$(8.34 + 18.7)M or \$27M.

NRC Cost: PNL estimated that it would require 16 man-weeks of staff effort to develop the possible solutions. At a rate of \$2,270/man-week, this amounts to \$36,000; contractor support is expected to cost an additional \$500,000. Therefore, the total NRC development cost is estimated to be \$536,000.

NRC effort to support industry implementation of the solutions is estimated to be 15 man-weeks/plant for those with heaters and 2 man-weeks/plant for those with cooling. Assuming a rate of \$2,270/man-week, the total NRC implementation costs are:

\$2,270 [(18 plants)(15 man-wk/plant) + (46 plants)(2 man-wk/plant)] = \$822,000.

NRC review time for operation and maintenance is estimated to be 1 man-week/RY for all affected plants. At a cost of \$2,270/man-week, the total NRC cost for review of operation and maintenance of the possible solutions over the 7-year vulnerability period is given by:

(64 plants)(7 years)(\$2,270/RY) = \$1.02M

Therefore, the total NRC cost for development, implementation, operation, and maintenance of the possible solutions is given by:

\$(536,000 + 822,000 + 1,020,000) = \$2.4M

Value/Impact Assessment

Based on a potential risk public reduction of 2.24×10^4 man-rem and a combined industry and NRC cost of \$22.1M, the value/impact score is given by:

$$S = \frac{2.24 \times 10^4 \text{ man-rem}}{\$29.4\text{M}}$$

$$= 762 \text{ man-rem/\$M}$$

Other Considerations

No occupational dose will be incurred during implementation, operation, and maintenance of the solutions at forward-fit plants. Based on a radiation field of 100 millirem/hr in the vicinity of the reactor vessel, PNL estimated the total occupational dose increase of the 64 backfit plants to be 1880 man-rem. Operation and maintenance of the solutions at these plants are estimated to result in an additional risk of 5100 man-rem. Thus, the total occupational dose increase from implementation, operation, and maintenance of the possible solutions is estimated to be 7000 man-rem.

Occupational dose reduction due to accident avoidance will be realized at the forward-fit plants, as well as at backfit plants, over the last 7 years of reactor operation. The occupational dose reduction due to accident avoidance was calculated to be 330 man-rem for all 78 affected plants.

CONCLUSION

Based on the potential public risk reduction and value/impact score, the issue would have a medium priority ranking. Consideration of the net occupational dose increase associated with the solutions does not change this conclusion. However, because the change in core-melt frequency from implementation of the proposed solutions was estimated to be 3.1×10^{-5}/RY for 99% of the affected plants (PWRs), this issue was given a HIGH priority ranking.

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ISSUE 82: BEYOND DESIGN BASIS ACCIDENTS IN SPENT FUEL POOLS

DESCRIPTION

Historical Background

The risks of beyond design basis accidents in the spent fuel storage pool were examined in WASH-1400[16] (App. I, pp. I-96ff). It was concluded that these risks were orders of magnitude below those involving the reactor core. The basic reason for this is the simplicity of the spent fuel storage pool--the coolant is at atmospheric pressure, the spent fuel is always subcritical and the heat source is low, there is no piping which can drain the pool, and there are no anticipated operational transients that could interrupt cooling or cause criticality.

The reasons for re-examination of spent fuel storage pool accidents are two-fold. First, spent fuel is being stored instead of reprocessed. This has led to the expansion of onsite fuel storage by means of high density storage racks, which results in a larger inventory of fission products in the pool, a greater heat load on the pool cooling system, and less distance between adjacent fuel assemblies. Second, some laboratory studies have provided evidence of the possibility of fire propagation between assemblies in an air-cooled environment.[543, 544] These two reasons, put together, provide the basis for an accident scenario which was not previously considered.

Safety Significance

A typical spent fuel storage pool with high density storage racks can hold roughly five times the fuel in the core. However, since reloads typically discharge one third of a core, much of the spent fuel stored in the pool will have had considerable decay time. This reduces the radioactive inventory somewhat. More importantly, after roughly three years of storage, spent fuel can be air-cooled, i.e., such fuel need not be submerged to prevent melting. (Submersion is still desirable for shielding and to reduce airborne activity, however.)

If the pool were to be drained of water, the discharged fuel from the last two refuelings would still be "fresh" enough to melt under decay heat. However, the zircaloy cladding of this fuel could be ignited during the heatup.[543] The resulting fire, in a pool equipped with high density storage racks, would probably spread to most or all of the fuel in the pool. The heat of combustion, in combination with decay heat, would certainly release considerable gap activity from the fuel and would probably drive "borderline aged" fuel into a molten condition. Moreover, if the fire becomes oxygen-starved (quite probable for a fire located in the bottom of a pit such as this), the hot zirconium would rob oxygen from the uranium dioxide fuel, forming a liquid mixture of metallic uranium, zirconium, oxidized zirconium, and dissolved uranium dioxide. This would cause a release of fission products from the fuel matrix quite comparable to that of molten fuel.[545] In addition, although confined, spent fuel pools are almost always located outside of the primary containment. Thus, release to the atmosphere is more likely than for comparable accidents involving the reactor core.

Possible Solutions

No generic solution to this potential problem has yet been identified. Several possibilities exist, however. The first possibility is to reprocess the spent fuel and thus reduce the inventory in the pool. Second, the pool could be compartmentalized by installing partitions (and individual coolant supply diffusers for each compartment) thus limiting the extent of an accident. Third, spray headers could be installed to provide cooling even when the pool is drained and not refloodable.

PRIORITY DETERMINATION

LWR spent fuel storage pools do not differ greatly. None are equipped with drains; a portable pump must be brought in when it is desired to empty the pool. The cooling systems are provided with anti-siphoning devices (check valves and/or anti-siphoning holes) so that pipe breaks in the cooling system will not drain the pool. All are seismic Category I. One difference does exist: PWR pools are generally below grade (often on bedrock) while BWR pools are considerably above grade. Thus, even a hole in the bottom of the pool will not rapidly drain a PWR pool. This priority determination, therefore, is concentrated on a BWR pool because of its (somewhat) greater vulnerability.

Frequency Estimate

BWR spent fuel can be uncovered either by extended loss of pool cooling, which results in boiloff, or by an accident which drains the pool. We shall consider both mechanisms.

Typically, a BWR spent fuel storage pool has no drains. Instead, coolant is withdrawn at the surface by skimmers which conduct the water into two surge tanks. The cooling system consists of two pumps and two heat exchangers which reject heat to the RBCCW system. These are not independent trains. The suction on the surge tanks is common and flow from the heat exchangers is combined to go through one filter/demineralizer before it is returned to the spent fuel pool. Return is by means of a set of diffusers located near the bottom of the pool. The piping connected to the diffusers contains check valves or some other anti-siphoning device.

Immediately after a refueling, both pumps and heat exchangers are usually needed. After a few months of decay, the heat load will diminish to the point where only one pump and heat exchanger are needed. Water makeup is normally via the condensate transfer system which is connected to one of the surge tanks.

The spent fuel pool cooling system is cross-connected to one train of the RHR system at both inlet and outlet. The primary reasons for this is to allow use of RHR for supplementary fuel pool cooling during periods when an entire reactor core is off-loaded. However, this also provides a backup means of pool cooling. In addition, since the RHR suction can be lined up to the condensate storage tank or even to river water, RHR also provides a backup means of maintaining pool water inventory.

Control and operation of the spent fuel pool cooling system and RHR cross-ties are not performed from the control room; most of the valves involved are manually operated. However, if pool cooling is lost, it will take over two days for the pool temperature to rise to boiling and at least two days more for the level to drop to the top of the fuel assemblies, even under design heat load conditions. Moreover, there are level alarms on the surge tanks and the pool itself in the control room. Thus, even though the systems are not automatic, the long time intervals involved should be sufficient to prevent problems with human confusion, etc.

WASH-1400[16] estimated the frequency of loss of one spent fuel pool cooling "train" to be 0.1/RY. We will assume, based on experience with other systems, that the conditional probabilities of the second "train" also failing due to a common-mode problem is 5%, and due to a random failure, 1.5%. In addition to this, the second pump and heat exchanger are in use (i.e., are not a redundant backup) about 30% of the time. Thus, the combined frequency of a pool heatup event is 3.7×10^{-2}/RY.

To go from a pool heatup event to an event that threatens the fuel, several other failures must occur. First, the RHR system must fail, both as a cooling system and as a supply of makeup water. For this, we assume a conditional probability of 1.5%, based on RHR reliability in the LPCI mode.[16] Second, the condensate transfer system could be used as a makeup system, either by supply to the fuel pool cooling system suction or (if the pool cooling system is isolated) by overfilling the surge tanks and causing backflow into the fuel pool. Since the condensate system is not powered by emergency power buses, it may well be put out of service by any common mode failure of the spent fuel pool cooling system. Thus, we will assume a conditional failure probability of 5% for the condensate transfer system.

Ultimately, makeup to the pool could be supplied by bringing in a fire hose (60 gpm would suffice). Although one would expect that the failure probability associated with bringing in a hose (over a period of four or more days) would be very low, it must also be remembered that working next to 385,000 gallons of potentially contaminated boiling water on top of a 10-story building is not a trivial problem. We will assume, based purely on judgment, that the conditional failure probability for this method of makeup is on the order of 5%. When these probabilities are combined, the result is a frequency of 1.4×10^{-6}/RY for an accident initiated by loss of spent fuel pool cooling.

Several events could cause an accident by draining the pool. We will first examine those events which are not likely to cause gross failure of the confinement system. First, there is the possibility of a break in the cooling system (beyond the condensate transfer makeup capacity) which we estimate to happen no more often than once per thousand reactor-years (the "S2" frequency). To drain the pool, the anti-siphoning check valves must fail (conditional probability of 8%, based on a German component failure study) and there must be a failure of the pool cooling system to isolate (conditional failure probability of 1%, based purely on judgment). RHR should provide sifficient makeup, since each RHR pump can supply 10,000 gpm and normal maximum fuel pool flow is 1200 gpm. However, RHR may be inoperable, for which we assume a conditional probability of 1.5% (based on WASH-1400).[16] When these figures are combined, the siphoning scenario is estimated to occur with a frequency of 1.2×10^{-8}/RY.

In addition, the pool could be drained by a cask drop accident (2.5×10^{-7}/RY, from WASH-1400)[16] or a turbine missile (4.1×10^{-7}/RY, also from WASH-1400).[16] Here, the RHR might not have sufficient capacity and the time frame is not as long as the previous scenarios. We will assume, based again on judgment, that the combined RHR conditional failure probability is 10%. This gives an accident frequency of 6.6×10^{-8}/RY. If we add the 1.2×10^{-8}/RY from the siphoning scenario, the total frequency for this class of accidents is 7.8×10^{-8}/RY.

Finally, we come to two scenarios which could open up the pool to the atmosphere as well as drain it. First, there is the tornado missile ($\leq 5 \times 10^{-6}$/RY, from WASH-1400).[16] This should not simultaneously cause failure of RHR. However, RHR may be otherwise inoperable (in this shorter time frame) or have insufficient capacity. We will assume that the combined RHR conditional failure probability if 5%. This gives an accident frequency of 2.5×10^{-7}/RY. Second, a seismic event could breach the pool. The WASH-1400[16] estimate for this is 10^{-5} to 10^{-7}/RY, depending on the site. We will use the higher figure, recognizing that this will limit the number of sites to which the analysis will apply.

After a seismic event severe enough to breach a seismic Category I spent fuel pool, the probability of RHR failure is higher than that of our previous scenarios. Moreover, the RHR might not be able to supply enough makeup. Finally, the time frame is very short, considering that manual valves must be opened and other earthquake-induced problems may be distracting plant personnel. We will assume that 90% of the time the draining rate will be slow enough to both be within the capacity of RHR makeup and also allow operator diagnosis and the necessary manual lineup of RHR to the pool. We will further assume a 90% probability of RHR remaining operable after the earthquake. This gives a total failure conditional probability of 19%.

Thus, for a site with a high seismic probability, the frequency of earthquake-induced accidents is estimated to be 1.9×10^{-6}/RY. Adding the tornado-induced accident frequency to this, we get a frequency for this class of accidents of 2.2×10^{-6}/RY.

Consequence Estimate

A BWR spent fuel storage pool with high density racks may contain almost 3500 fuel bundles, which is about 4½ times the inventory of the reactor core. Thus, an accident in the spent fuel pool can threaten much more fuel than a reactor accident. Compensating for this is the fact that much of the stored spent fuel has had considerable time for decay of hazardous radioactive fission products. To estimate the hazard to the public from melting of the spent fuel pool inventory, special CRAC2 runs were performed,[546] using a uniform population density of 340 persons per square mile, a central midwest plain meteorology, and no ingestion pathways. The calculations were performed for a spent fuel pool with a series of 1/3-core reload modules. The first module had one week decay time, the second, 18 months, the third, 3 years, and so on for a total of 13 modules. Cases were run using release fractions from the BWR-2, BWR-3 and BWR-4 release categories. This corresponds to release direct to atmosphere, release through a hole in the secondary containment, and release with the containment at design leakage and SGTS operable.

The results of the calculations and their corresponding frequencies from the previous section are:

Analagous Release Category	Frequency (RY^{-1})	Consequences (man-rem)	Product (man-rem/RY)
BWR-2	2.2×10^{-6}	7.4×10^{6}	16.3
BWR-3	7.8×10^{-8}	6.5×10^{6}	0.5
BWR-4	1.4×10^{-6}	1.1×10^{6}	1.5
		Total	18.3

It should be noted that this analysis is predicated on the assumption that the exposed elements will burn and that the fire will propagate throughout the pool. Additional research is necessary to substantiate this hypothesis. Assuming a a 40-year plant life, the total risk reduction per reactor is approximately 700 man-rem.

Cost Estimate

As was discussed previously, no specific solution to this potential problem has yet been settled upon. However, any hardware addition would probably have to be seismic Category I and, thus, costs are unlikely to be less than one million dollars per reactor. NRC costs will be negligible compared to licensee costs.

Value/Impact Assessment

Based on a risk reduction of 700 man-rem/reactor, the value/impact score is given by:

$$S = \frac{700 \text{ man-rem/reactor}}{\$1M/\text{reactor}}$$

$$= 700 \text{ man-rem/\$M}$$

Other Considerations

It should be noted that a low seismic probability will drop the above estimates to about 200 man-rem/reactor and 200 man-rem/$M. This will not change the final conclusion. In any case, this analysis was based on a specific pool design which was picked in an attempt to represent both generic and worst-case situations. The number of plants actually at risk may be limited.

CONCLUSION

Based on the available information and the above calculations, this item was given a medium priority ranking. Studies performed by the staff in resolving the issue showed that, although most of the spent fuel pool risk comes from beyond design basis earthquakes, this risk is no greater than the risk from core damage accidents due to seismic events beyond the safe shutdown earthquake. The staff's technical findings were published in NUREG/CR-4982,[1157] NUREG/CR-5176,[1196] and NUREG/CR-5281.[1197] The regulatory analysis published in NUREG-1353[1198] showed that there was no cost-effective alternative which, if implemented, would result in a substantial safety improvement.

The staff concluded that reducing the risk from spent fuel pools due to events beyond the SSE would still leave a comparable risk due to core damage accidents. Because of the large inherent safety margins in the design and construction of spent fuel pools, this issue was RESOLVED and no new requirements were established.[1199]

REFERENCES

16. WASH-1400 (NUREG-75/014), "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," U.S. Nuclear Regulatory Commission, October 1975.

543. Memorandum for T. Speis from R. Mattson, "Proposed Generic Issue on Beyond Design Basis Accidents in Spent Fuel Pools," August 10, 1983.

544. NUREG/CR-0649, "Spent Fuel Heatup Following Loss of Water During Storage," U.S. Nuclear Regulatory Commission, May 1979.

545. Memorandum for Z. Rosztoczy from P. Williams, "Trip Report: International Meeting on Severe Fuel Damage and Visit to Power Burst Facility," April 25, 1983.

546. Letter to H. VanderMolen (NRC) from D. Strenge (PNL), September 30, 1983.

1157. NUREG/CR-4982, "Severe Accidents in Spent Fuel Pools in Support of Generic Safety Issue 82," U.S. Nuclear Regulatory Commission, July 1987.

1196. NUREG/CR-5176, "Seismic Failure and Cask Drop Analyses of the Spent Fuel Pools at Two Representative Nuclear Power Plants," U.S. Nuclear Regulatory Commission, January 1989.

1197. NUREG/CR-5281, "Value/Impact Analyses of Accident Preventive and Mitigative Options for Spent Fuel Pools," U.S. Nuclear Regulatory Commission, March 1989.

1198. NUREG-1353, "Regulatory Analysis for the Resolution of Generic Issue 82 'Beyond Design Basis Accidents in Spent Fuel Pools,'" U.S. Nuclear Regulatory Commission, April 1989.

1199. Memorandum for V. Stello from E. Beckjord, "Resolution of Generic Issue, 'Beyond Design Basis Accidents in Spent Fuel Pools,'" April 24, 1989.

ISSUE 101: BWR WATER LEVEL REDUNDANCY

DESCRIPTION

Historical Background

Issue 50 addressed several areas of concern with BWR water level instrumentation and its resolution involved voluntary implementation of water level measurement improvements for all of the staff concerns, except the one related to a break in an instrument line in conjunction with the worst single failure.[720]

This concern was first identified in an AEOD draft report[721] which was later issued as AEOD/C201[322] in January 1982. In the interest of the expeditious resolution of Issue 50, it was decided[697] to address the AEOD concern as Issue 101.

Safety Significance

Water level is measured in BWRs by means of differential pressure sensors connected between the reactor vessel (at a point low enough in elevation to be below the expected water level) and reference columns (which are completely full of water and connected at the top to the steam dome). The differential pressure sensed by the dp cell corresponds to the difference in elevation between the "collapsed" water level in the reactor and the water level in the reference column. If the reference column is broken, the water in it will flash to steam and the water level indication in all channels connected to the broken column will give a false "high" reading.

Typically, a BWR will have two reference columns. (There is a variety of design, however.) A break in one column will cause all instrumentation associated with that column to indicate full scale high level. This can simultaneously cause a transient and interfere with safety systems. A single failure associated with the other reference column can completely defeat mitigation systems. The following points were stated in an RRAB memorandum:[722]

> "Consequences of such an event depend upon (1) the location of the postulated reference leg break, whether it is a single reference leg or a common line; (2) the physical location of an additional postulated single failure, and (3) the various combinations thereof.
>
> "Further, effects of such an event depend upon plant specific design. In some older plants, a postulated reference leg break itself without any additional single failure will cause failure of ECCS initiation due to a reactor water level condition.
>
> "The greatest vulnerability occurs when the same sensor is used to initiate more than one system. In one plant where core spray initiation and MSIV initiation share the same set of sensors, a single failure in either system in addition to a pipeline break in the instrument reference leg may cause a core uncovery. In another plant, the consequences of the additional single failure becomes of concern only when the coolant injection system initiation transmitter fails. In such an event, operator action is required to prevent

core uncovery in about 45 minutes. Further, several indications are available in the control room to give the operator information relative to the accident progression and status of the plant."

Possible Solution

The references cited above do not recommend specific modifications since individual plant designs are apparently too varied to permit generic solutions.[723] However, it appears to be possible to fix the problem by modification to the logics which use reactor level as an input.[722]

PRIORITY DETERMINATION

Frequency/Consequence Estimate

The RRAB memorandum[722] contains a probabilistic assessment of the concern. This assessment estimated a core-melt frequency of 10^{-5}/RY and a public risk of 50 man-rem/RY. The affected plants were estimated to have roughly 20 effective full-power years of remaining life for a total risk of 1,000 man-rem/reactor.

Cost Estimate

The RRAB assessment[722] contained a cost-benefit ratio of \$1,000/man-rem for the concern in this issue. This translates into \$1M/reactor.

Value/Impact Assessment

Based on an estimated risk reduction of 1,000 man-rem/reactor and a cost of \$1M/reactor, the value/impact score is given by:

$$S = \frac{1{,}000 \text{ man-rem/reactor}}{\$1\text{M/reactor}}$$

$$= 1{,}000 \text{ man-rem/\$M}$$

Other Considerations

It must be emphasized (as virtually every reference points out) that both the affected accident sequences and the modifications to resolve the issue will vary from plant to plant. The resolution of this issue will be more case-specific than most and some plants may not require modification.

The RRAB calculations[722] assume an operator error probability of 0.1. This figure is based on judgment balancing the relatively high likelihood of initial operator confusion, due to conflicting level indicators, against a relatively long time (45 minutes) available for problem diagnosis before core uncovery in the primary sequence. Specific plant designs and other more rapid sequences may well indicate a higher figure for operator error probability, which would increase the priority figures above.

In some cases, ORE associated with the modifications may be a significant factor. This area should be addressed in specific plant reviews.

CONCLUSION

The priority parameters were on the borderline between medium and high priority; however, it was believed that some specific plants would fall well into the high area, others well into medium or below. At the time of prioritization, the specific plants for which this issue was particularly important could not be identified. Therefore, this issue was given a high priority.

In resolving this issue, the staff concluded that all BWR designs, in conjunction with operator training and procedures, provide adequate protection in the event of an instrument line break in any of the reactor vessel water level instrument systems. The staff believed that emergency procedures for an operator to identify and mitigate the consequences of instrument line breaks exist at all plants and that reactor operators were being trained to achieve safe shutdown, if needed. The technical basis for this conclusion was documented in NUREG/CR-5112[1212] in which plant-specific design features, such as common sensing lines for the water level instrumentation, automatic initiation logic for vital protection systems, inhibition of vital protection systems, and additional single failures of safety-related and non-safety-related systems, were considered. The results, including the value/impact analyses of the alternatives considered for plant improvements for BWR plant designs, were provided for information.

Generic Letter 89-11[1213] was issued to all holders of OLs and CPs for BWRs with the expectation that the information provided would be reviewed to verify that the design of the affected plants had been correctly represented. The staff recommended that consideration be given to a reassessment of plant procedures and operator training to ensure that plant operators can readily detect and mitigate a leak or break of a sensing line. Thus, this issue was RESOLVED and no new requirements were established.[1214]

REFERENCES

322. AEOD/C201, "Report on the Safety Concern Associated with Reactor Vessel Level Instrumentation in Boiling Water Reactors," Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, January 1982.

697. Memorandum for D. Eisenhut from R. Bernero, "Resolution of Generic Issue 50, Reactor Vessel Level Instrumentation in BWR," September 6, 1984.

720. Memorandum for T. Speis from R. Bernero, "Request for Prioritization of Generic Safety Issue - Break Plus Single Failure in BWR Water Level Instrumentation," October 10, 1984.

721. Memorandum for H. Denton and V. Stello from C. Michelson, "Case Study Report - Safety Concern Associated with Reactor Vessel Instrumentation in Boiling Water Reactors," September 2, 1981.

722. Memorandum for B. Sheron from A. Thadani, "Reactor Vessel Level Instrumentation in BWR's (Generic Issue 50)," August 2, 1984.

723. Memorandum for H. Denton from T. Speis, "Reactor Vessel Level Instrumentation in BWRs (Generic Issue 50)," August 2, 1984.

1212. NUREG/CR-5112, "Evaluation of Boiling Water Reactor Water-Level Sensing Line Break and Single Failure," U.S. Nuclear Regulatory Commission, March 1989.

1213. NRC Letter to All Holders of Operating Licenses or Construction Permits for Boiling Water Reactors, "Resolution of Generic Issue 101, 'Boiling Water Reactor Water Level Redundancy' (Generic Letter 89-11)," June 30, 1989.

1214. Memorandum for V. Stello from E. Beckjord, "Closeout of GI 101, 'Boiling Water Reactor Water Level Redundancy,'" April 24, 1989.

ISSUE 115: ENHANCEMENT OF THE RELIABILITY OF WESTINGHOUSE SOLID STATE PROTECTION SYSTEM

DESCRIPTION

Historical Background

The ATWS rule[724,725] for W plants requires the implementation of a diverse ATWS mitigation system, Auxiliary [or ATWS] Mitigating Systems Actuation Circuitry (AMSAC). The functions prescribed for AMSAC are turbine trip and the initiation of auxiliary feedwater, independent of the reactor trip system.

As a consequence of the Salem ATWS event (Issue 75), Generic Letter 83-28[520] established the requirement for the automatic actuation of the shunt trip attachment of reactor trip breakers for W and B&W plants (this feature was included in the original design for CE plants). Although this modification provides a significant increase in the reliability of the reactor trip breakers and hence the reactor trip system, it had not been previously pursued as an action which would significantly reduce the potential of an ATWS event during the extensive dialogue and study of the ATWS issue. Further, it is believed that other similar actions to increase the reliability of the existing reactor trip system for W plants have also not received such consideration.

With respect to W plants with the solid state protection system (SSPS) design, recent failures of the undervoltage (UV) driver have raised concerns with regard to the susceptibility of the design to common mode and random failures of redundant components. Enhancement of the reliability of the W SSPS was suggested by DSI as a new generic issue in April 1985.[905]

Safety Significance

The recent failures of the UV driver suggest a higher probability of SSPS failure than that calculated during the ATWS rulemaking proceeding. The higher probability of SSPS failure in turn would lead to a higher probability of ATWS and, as such, would represent a higher risk to the offsite population surrounding the affected plants. The affected plants are those W plants with the SSPS: 19 of the 38 currently operating W plants.

Possible Solution

Incorporation of additional diversity for the UV driver function would reduce the probability of an ATWS event. In particular, it is assumed that the UV driver reliability can be improved by installing a relay driver and associated relays to duplicate the function of the UV driver, thereby providing diversity for the function.

PRIORITY DETERMINATION

The analysis described herein was performed by PNL[64] based on an ICSB analysis. For the purpose of this evaluation, it is assumed that the AMSAC required by the ATWS rule for W plants is in place and operational.

Frequency Estimate

Reliability block diagrams for the W SSPS were used in the calculation of frequency estimates of core damage events as a result of SSPS failures. These figures were provided to the staff as part of the W Owners Group response to staff questions during the review of WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection System," (Proprietary). Diversity exists in two basic forms. The first is from the standpoint of measured parameters and sensors that initiate a reactor trip and the second is the diverse trip features of the reactor trip breakers (shunt and UV trip coils). For the analog channels, comparators are the major component that are common to each channel. For the logic cabinet, input relays and the universal (logic) cards are common for each trip function, with the UV driver common to all trip functions. For the reactor trip breakers, the remaining components (primarily mechanical) are common to all trip functions.

Table 3.115-1 summarizes the estimates for common mode failures of the protection system on the bases of the listed failure rates, a Beta factor of 0.01 and a monthly test interval. A Beta factor of 0.01 is used to be consistent with that used for logic channels as noted in SECY 83-293.[904] Currently, TS require testing of breakers and logic every 62 days on a staggered test basis (one train or the other is tested every 31 days such that the time interval for finding common mode failures would be monthly). Based on the review of WCAP-10271, the staff approved quarterly testing of analog channels. Since the majority of the trip functions consist of 3 or 4 channels, quarterly tests on a staggered test basis for a 3-channel system results in one channel being tested monthly. Thus, a monthly test interval is also used for analog channels.

The channel comparators are the major contributor to the common mode failure unavailability since they have the largest hourly failure rate. However, if the hourly failure rate for the UV driver is estimated based on five known failures to date and an estimate of 90 RY for W plants that have the SSPS with two UV drivers, the common mode failure unavailability of the UV driver (see Table 3.115-2) becomes the dominant contributor.

In addition to initiating reactor trip, the SSPS is used to initiate engineering safeguard systems. While these functions of the protection system use many of the same components as the reactor trip system (comparators, logic input relays, and universal logic cards), it differs from the reactor trip system in its final output configuration. Instead of a UV driver that turns off 48V DC to the actuated component, a relay driver is provided which supplies 48V DC to energize a master relay which in turn energizes slave relays that provide contacts to actuate engineered safeguard components. Thus, a relay driver and associated relays could be used to duplicate the function of the UV driver for the reactor trip function and thereby provide diversity. This would eliminate common mode failures of the UV driver as the dominant contributor to the probability of an ATWS event due to protection systems failures (see Table 3.115-3).

The event trees used by the ATWS Task Force were altered to substitute the above estimates of SSPS electrical unavailability for the value previously used to estimate a base case frequency of core damage events and a core damage frequency after supplementing the UV driver function. Values for the probability of all other events were those used by the ATWS Task Force. The specific events

TABLE 3.115-1

Components	Common Mode[a] Failure Unavailability (10^{-5})
Channel Comparators ($\lambda = 2.9 \times 10^{-6}$/hr)	1.1
Logic Input Relays ($\lambda = 8.7 \times 10^{-8}$/hr)	0.032
Universal Logic Cards ($\lambda = 7.7 \times 10^{-7}$/hr)	0.29
Undervoltage Driver ($\lambda = 1.95 \times 10^{-7}$/hr)	0.073
Breaker Mechanical Components ($\lambda = 1.95 \times 10^{-8}$/hr)	0.031
Total:	1.53

(a) $U = \frac{B\lambda T}{2}$ (Average unavailability due to common mode failure)

TABLE 3.115-2

Undervoltage Driver Failures	5
Reactor-Years (Est) SSPS Plants	90
Failure Rate, λ	0.028/yr (3.17×10^{-6}/hr)
Common Mode Failure Probability[a]	1.14×10^{-5}
All other components $(1.53 - 0.073) \times 10^{-5}$	1.46×10^{-5}
Total Failure Probability	2.6×10^{-5}

(a) $U = \frac{B\lambda T}{2}$ (Average unavailability due to common mode failure)

TABLE 3.115-3

Total System Unavailability

	Present System	Diverse UV Driver
Common Mode failures	2.60×10^{-5}	1.46×10^{-5}
Random failures	4.33×10^{-6}	(b)
Testing	6.34×10^{-6}	(b)
	3.67×10^{-5}	1.46×10^{-5}

(b) The additional diversity decreases the random failure unavailability to less than 10^{-6} and eliminates testing unavailability.

incorporated in the event trees are Number of Transients (AT), MTC Overpressure, SSPS Mechanical failure, Auxiliary Feedwater Failure, and High Pressure Injection (HPI) failure. The base case frequency of core damage events is estimated to be 8.9×10^{-6}/RY when the five recent UV driver failures are considered. The frequency of core damage events is estimated to be 4.7×10^{-6}/RY when the increased reliability of SSPS afforded by supplementing the UV driver function is considered. This results in a reduction in core-melt frequency of 4.2×10^{-6}/RY for the proposed modification to the SSPS.

Consequence Estimate

The total whole-body man-rem dose is obtained using the CRAC code results.[64] The results assume a uniform population density of 340 people per square mile (which is the average for U.S. domestic sites in the year 2000) within the area between 1/2- and 50-mile radius from the plant. Typical (Midwest plain) meteorology, no evacuation and no ingestion were also assumed. The Oconee 3 RSSMAP study has been adopted as the evaluation model for PWRs and is therefore assumed to adequately represent the selected group of affected plants for this issue. In the Oconee 3 RSSMAP, the only ATWS dominant risk sequence (T_2KMU) is assumed to result in a Category 3 release with a probability of 0.5, a Category 5 release with a probability of 0.007, and a Category 7 release with a probability of 0.5. Thus, we have derived a weighted average of 2.7×10^6 man-rem/event for the consequences of ATWS events using the CRAC code results. (It should be noted that the ATWS Task Force assumed a consequence, in terms of public exposure, of 10^7 man-rem/event in arriving at their recommendations.)

The 19 W operating plants utilizing the SSPS have an average remaining lifetime of 25.5 years. When the estimate reduction in core-melt frequency (4.2×10^{-6}/RY) is multiplied by the average consequence (2.7×10^6 man-rem/event), the number of affected plants (19 plants) and the average remaining lifetime of the affected plants (25.5 years), an estimate of 5,500 man-rem is obtained.

Cost Estimate

Industry Cost: Based upon discussions with plant operators, the following licensee implementation costs have been identified:

(1) Engineering analysis of the problem is estimated to take about 2 man-weeks. This is to design and document the modifications to the SSPS. At \$2,270/man-wk, this is estimated to cost \$4,540.

(2) Relays and other hardware are assumed to cost \$3,000.

(3) Installation is assumed to require 1 man-wk at an estimated cost of \$2,270. Since this modification can be completed during normal outage time, no replacement power cost has been included.

(4) Possible TS changes are assumed to require 4 man-wks. At \$2,270/man-wk, this is estimated to cost \$9,080.

In addition, we assumed that following completion of the modifications to the scram system of the SSPS, a functional (acceptance) test would be necessary. We estimate that this test would take the better part of a shift to perform and would involve time from the shift supervisor, systems engineering, control room operators and I&C technicians. Forty-two man-hours total are estimated for a cost of $2,400/plant.

QA efforts during the design, installation and testing of the scram system modifications and during the development of TS revisions are estimated to expend an additional 66 man-hours for a cost of $3,800/plant.

The total cost of the above requirements is estimated to be about $25,000/plant or a total licensee implementation cost of $475,000 for the 19 affected plants.

The affected plants are assumed not to require any additional operation/maintenance beyond that normally required. Therefore, the licensees' operation and maintenance cost is zero.

NRC Cost: It is estimated that total NRC labor requirement for development of requirements is 8 man-weeks. At $2,270/man-wk, this is estimated to be $18,160. The cost for a technical assistance contractor is assumed to be $20,000. Therefore, the total NRC cost for development of requirements is ($18,160 + $20,000) = $38,000.

NRC cost tracking has shown that, on the average, it requires about 1.7 staff-years to process a generic requirement from the point at which it is acted on by the CRGR until its resolution in the form of a specific MPA. At approximately $135,000/staff-year, this amounts to about $230,000. In light of the relatively large societal risk and the rather small industry costs estimated for this issue, we assumed that the NRC requirement processing costs would be less than the current average and would be about $150,000.

Using historical cost information provided in NUREG/CR-3971,[906] we have estimated the NRR implementation costs per plant for the plant-specific review of licensee design changes, the review and processing of plant-specific TS changes, and OIE review of the licensees' implementation actions. The estimated NRC implementation costs are:

NRC Design Review	$ 6,000
TS Review and Processing	14,000
OIE Implementation Review	4,000
TOTAL:	$24,000/plant

For the 19 affected plants, the NRC implementation cost is estimated to be $456,000. Since no additional operational/maintenance costs were estimated for the licensees, no additional costs for NRC review of the licensees maintenance and testing is estimated. Thus, the total NRC costs are estimated to be $644,000.

The summation of licensee and NRC total costs results in an estimate of $1.12M for the resolution and implementation of this issue.

Value/Impact Assessment

Based on a total risk reduction of 5,500 man-rem for 19 W PWRs, the value/impact score is given by:

$$S = \frac{5.5 \times 10^3 \text{ man-rem}}{\$1.12M}$$

$$= 4.9 \times 10^3 \text{ man-rem/\$M}$$

Other Considerations

Reduction in the frequency of core damage events will result in an averted ORE for cleanup of the 19 affected plants. When a value of 19,900 man-rem/event for ORE following a severe core damage event is multiplied by the change in core-melt frequency, the number of affected plants and their average remaining lifetime, an averted ORE of about 40 man-rem is estimated. Likewise, the rather large reduction in core-melt frequency would also result in an appreciable averted accident savings to the licensee. At a cost of $1.65 billion per core-melt event, the averted accident savings for this issue is calculated to be $3.3M.

Based on discussions with plant operators, the assumed modifications to the SSPS would not require labor for installation or maintenance in a radiation zone. Therefore, no ORE is estimated for these efforts.

The proposed modifications to the SSPS might result in an increase in the frequency of inadvertent or spurious trips which would represent an economic loss to the industry due to lost power production/replacement power costs. This was not considered in this analysis but should be estimated and accounted for in the resolution of this issue and the development of a Regulatory Analysis for any proposed new requirement(s).

CONCLUSION

The significant potential risk reduction estimate and the high value/impact score indicated that this issue be treated with high priority. W investigated the five UV driver card failures and determined that they were caused by poor maintenance and test-related practices. These practices involved the inadvertent shorting of the scram breakers' UV trip coil, causing a shorted failure of the output transistor in the UV card. To eliminate this safety problem, W modified the design of the UV card to provide a fuse link in the output circuit which will open the circuit when the UV coil is shorted. This will produce a UV trip signal to the scram breaker which will persist until the card is removed, repaired (by W), and replaced. W Technical Bulletin NSID-T8-85-16 dated July 31, 1985, was issued to the W utilities, as required by the Salem ATWS Generic Letter (83-28),[520] recommending installation of the modified UV cards. The Bulletin also recommended specific maintenance and test procedures that should be followed to prevent failures of this type pending installation of the modified UV cards. It was expected that the affected W licensees have taken or will take action to modify their test and maintenance procedures and to procure and install the modified UV driver cards. The staff sought verification of the licensees' responses to the W recommendations. The W recommended solution was not viewed as providing the same degree of risk reduction as that which could be altered by providing diversity for the UV drive scram function. Resolution of this generic issue should recognize the potential risk reduction afforded by the W "fix" if it is adopted by the affected licensees and a determination made as to whether any further risk reduction offered by providing diversity for the UV driver scram function can be justified by value/impact analysis.

In the course of resolving this issue, the staff gained certain insights which were deemed to be useful in improving the reliability and overall performance of reactor protection systems. These insights were suitable for industry initiatives to improve safety and to reduce the regulatory burden on the affected licensees while extending the life of reactor trip breakers. The staff's technical findings were documented in NUREG/CR-5197;[1200] the regulatory analysis was published in NUREG-1341.[1201] Thus, this issue was RESOLVED and no new requirements were established.[1202]

REFERENCES

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

520. NRC Letter to All Licensees of Operating Reactors, Applicants for Operating Licenses, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events," (Generic Letter No. 83-28), July 8, 1983.

724. Memorandum for W. Dircks, et al., from S. Chilk, "Staff Requirements - Affirmation/Discussion and Vote, 11:30 a.m., Friday, June 1, 1984, Commissioners' Conference Room, D.C. Office (Open to Public Attendance)," June 1, 1984.

725. Federal Register Notice 49 FR 26036, "10 CFR Part 50, Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water Cooled Nuclear Power Plants," June 26, 1984.

904. SECY-83-293, "Amendments to 10 CFR 50 Related to Anticipated Transients Without Scram (ATWS) Events," July 19, 1983.

905. Memorandum for T. Speis from R. Bernero, "Enhancement of the Reliability of W Solid State Protection Systems (SSPS)," April 5, 1985.

906. NUREG/CR-3971, "A Handbook for Cost Estimating," U.S. Nuclear Regulatory Commission, October 1984.

1200. NUREG/CR-5197, "Evaluation of Generic Issue 115, 'Enhancement of the Reliability of Westinghouse Solid State Protection System,'" U.S. Nuclear Regulatory Commission, January 1989.

1201. NUREG-1341, "Regulatory Analysis for the Resolution of Generic Issue 115, 'Enhancement of the Reliability of the Westinghouse Solid State Protection System,'" U.S. Nuclear Regulatory Commission, May 1989.

1202. Memorandum for V. Stello from E. Beckjord, "Resolution of Generic Issue 115, 'Enhancement of the Reliability of Westinghouse Solid State Protection Systems,' NUREG-1341," April 17, 1989.

ISSUE 122: DAVIS-BESSE LOSS OF ALL FEEDWATER EVENT OF JUNE 9, 1985 - SHORT-TERM ACTIONS

The loss of all feedwater event at Davis-Besse on June 9, 1985 resulted in the formation of an NRC project team to investigate the event. The team's findings were published in NUREG-1154[886] and were subsequently reviewed by DL. As a result of DL's review, the following items were identified as candidates for short-term staff action[885] and were forwarded to DST for prioritization:[887]

1. Potential inability to remove reactor decay heat due to questionable reliability of the auxiliary feedwater system caused by any or all of the following:

    a. Loss of all auxiliary feedwater due to common-mode failure of AFW pump discharge isolation valves in closed position.

    b. Excessive delay in recovery of auxiliary feedwater due to difficulty in restarting AFW pump steam driven turbines, if turbines are tripped.

    c. Interruption of auxiliary feedwater flow due to failures in steam and feed line break accident mitigation features (e.g., SFRCS).

2. Adequacy of emergency procedures, operator training and available plant monitoring systems for determining need to initiate feed-and-bleed cooling following loss of steam generator heat sink.

3. Physical security system constraints which could deny timely operator access to vital equipment and inhibit operator from performing local manual operations called for in emergency procedures.

The above items formed the basis for Issue 122 but were prioritized separately as shown below. The identification of each item prioritized follows the numbering system established in the DL memorandum.[885] The prioritization results are summarized in Table 3.122-1.

ITEM 122.1: POTENTIAL INABILITY TO REMOVE REACTOR DECAY HEAT

During the loss of main feedwater event, the reactor scrammed and the AFW system should have actuated and supplied feedwater to the steam generators to enable them to remove decay heat. However, in this process several failures occurred, three of which are of significance here.

(1) An operator attempted to start the two AFW trains manually, in addition to the automatic signal on low steam generator water level. Unfortunately, the operator pressed the wrong buttons, sending erroneous "low steam generator pressure" signals to both AFW trains. The AFW control systems

TABLE 3.122-1

Item	Staff Action	Priority
1.a	Common Mode Failure of AFW Pump Discharge Isolation Valves in Closed Position	HIGH
1.b	Excessive Delay in Recovery of Auxiliary Feedwater	MEDIUM
1.c	Interruption of Auxiliary Feedwater Flow	HIGH
2.	Adequacy of Emergency Procedures, Operator Training and Available Plant Monitoring Systems	HIGH
3.	Physical Security System Constraints	LOW

then caused both AFW isolation valves to close. Thus, neither steam generator could receive any water. In essence, the operator caused a common mode failure.

(2) Both AFW turbines tripped on overspeed. The overspeed trips on such turbines usually have to be reset at the turbine, not from the control room.

(3) In attempting to recover the AFW system, the operators reset the erroneous signals. However, the AFW isolation valves did not open. In spite of several attempts, the plant operators were unable to open these valves from the control room, and ultimately had to open them by hand.

The three parts of this item are evaluated separately below.

ITEM 122.1.A: FAILURE OF ISOLATION VALVES IN CLOSED POSITION

DESCRIPTION

Historical Background

This item addresses Findings 4, 5, 6, and 15 in Section 5.2.5 of NUREG-1154.[886] The particular issue deals with a potential inability to remove reactor decay heat because of loss of all auxiliary feedwater due to the third common mode failure discussed above. This is the failure of AFW pump discharge isolation valves to reopen on command after they had closed.

Safety Significance

With the main feedwater out of service (the transient initiator), a spurious closing of these AFW valves cannot easily be rectified, leaving only feed-and-bleed techniques available for removal of decay heat. Westinghouse PWRs generally do not have such motor-operated isolation valves in the AFW discharge lines, but some W plants plus roughly 16 plants designed by B&W and CE in addition to Davis-Besse may be susceptible to this problem.

Possible Solutions

The failure of the Davis-Besse AFW valves to reopen was ultimately traced to the torque limit and bypass switches which control the motor operators of the valves. In essence, the high differential pressure across the closed valves necessitated a relatively large force for valve motion. The motor control switches were not adjusted to accommodate such a force. Such a failure can happen in two ways. First, the switches can be inadvertently mis-adjusted during routine maintenance. Second, the valve may be correctly maintained but the actuation system is not designed to provide for an open command to these valves (in some PWRs), or the torque necessary to reopen these valves under some conditions may be beyond the design capacity of the valve actuators. In the case of Davis-Besse, the valves were designed to close (which is their intended safety function), but apparently less attention was paid to their ability to reopen.

The solutions are implicit in the causes. For this prioritization we assume that the actuation system is equipped to issue open commands so the solution is to verify that the valves, as designed, are capable of reopening in the presence of a differential pressure, and upgrade the calibration and maintenance procedures.

PRIORITY DETERMINATION

Frequency Estimate

To estimate accident frequencies, we will follow the example[888] in which the relatively simple transient classifications of the Oconee RSSMAP study[54] were used, but frequency and probability estimates were taken from the more modern sources such as the more detailed PRA of Oconee 3 done by EPRI and Duke Power Co.[889]

The affected sequences in the RSSMAP study[54] are T_1M(LOPNRE)LU, T_2MLU and T_3M(PCSNR)LU, where

T_1 is a loss of offsite power (LOOP) transient with an assumed frequency of 0.05 transient/RY (or more).[890]

T_2 is a non-recoverable loss of the Power Conversion System caused by other than a LOOP, with an assumed frequency of 0.64 transient/RY based on the Oconee PRA.[889]

T_3 is a transient with the Power Conversion System initially available, with an assumed frequency of 5.7 transients/RY also based on the Oconee PRA.[889]

M This is a failure of the power conversion system. The probability is unity for T_1 and T_2 sequences. For T_3 sequences, we will use 3.7×10^{-3}, obtained by summing the failure modes listed in Section A8.3.8 of the Oconee PRA.[889]

LOPNRE This is the probability of non-recovery of offsite power in 40 minutes after a LOOP event. We estimate this to be roughly 0.25, based on the generic curves given in NUREG-1032.[890]

PCSNR This is the probability of non-recovery of the Power Conversion System (really, main feedwater) in 30 minutes. The Oconee PRA[889] uses 0.3 for a similar event (event REFDW2). It must be remembered that this figure is somewhat optimistic because of the ability to cross-connect at the Oconee site.

L is failure of the AFW system.

U is a failure to cool the core via feed-and-bleed. For Oconee and most other plants, this is essentially a failure of the high pressure ECCS. The assumed probability is 0.015 based on the Oconee PRA.[889]

The unquantified parameter is ΔL, the change in the AFW failure probability to be attributed to this issue. It is composed of three factors: the probability of spurious isolation, the probability of failure to reopen on demand, and the probability of failure of reopening (in time to prevent core damage) by manual action.

Davis-Besse has been in operation for eight years. The licensee reports a frequency of loss-of-feedwater events of 0.67/year.[891] Thus, the AFW system has had about five real challenges. One of these was the June 9, 1985 event where an operator inadvertently pushed the wrong button and caused a spurious isolation. One would therefore expect the spurious isolation rate to be roughly one in five AFW demands, or 20%, and dominated by human error. However, it would be naive to assume that this event (and its associated extended shutdown) has gone unnoticed in the control rooms of other plants. Nor can it be assumed that all other plants have an AFW control panel like that of Davis-Besse. On the other hand, the AFW discharge isolation valves may be initially closed at the time of the demand, as they were at the outset of the accident at TMI-2. We will assume a 5% minimum likelihood of spurious or inadvertent AFW isolation and assume further that plants with a high (e.g., 20%) likelihood will be addressed by Item 122.1.C.

Next is the question of failure of the isolation valves to open on demand. As was mentioned before, this can happen either by errors in maintenance or by a lack of foresight in design. For the case of errors in maintenance, we turn to the valve failure data tabulated in NUREG/CR-2770.[892] Of the 393 MOV failures listed, 75 involved torque limit or bypass switches, and 34 of these (about 8.7% of all the failures) appeared to be adjustment or calibration errors. Since the same crews and procedures are used on all AFW trains, these failures are very likely to be present on all trains. Given a failure on one train, we will assume an 8.7% probability[892] that the failure was due to improper torque or limit switch adjustment and that the analogous valves on the redundant trains will also fail. The RSSMAP study[54] used an MOV control failure rate of 6.4×10^{-3}/demand. The probability of failure to reopen due to maintenance error is the product of these two figures, or 5.6×10^{-4}.

For the case of lack of foresight in design, there is no extensive tabular data. This particular scenario, by its very nature, will affect both valves. However, this does not mean that both valves necessarily will fail to open. NUREG-1154[886] describes tests of the actual valves at Davis-Besse, five of which were at a full differential pressure of 1050 psid. One valve failed to open twice. The other valve failed once but opened successfully two times. Thus, for a two-train AFW system, the probability of neither valve opening would be expected to be on the order of (1 x 0.33), or 33%, based on this admittedly sparse data.

Finally, the probability of the operator failing to reopen the valves manually must be estimated. In the case of the Davis-Besse event, the spurious closure occurred about six minutes into the event. NUREG-1154[886] mentions a 30-minute interval before core damage would be expected. Thus, the operators had about 24 minutes in which to reopen at least one valve. In actual fact, it took an average of 7.5 minutes (about a third of the available time) to open these two valves. This is plenty of margin and would normally imply a failure rate (due to timeout) of a percent or two. However, it should be noted that, except for one button-pushing error (which is understandable in the light of hindsight), this operating crew performed very well. The shift supervisor and his assistant were astute in diagnosing the AFWS misalignment (while being faced with a barrage of other information) and took the correct action to manually open the auxiliary feedwater block valves. We will assign a 10% probability of failure to manually reopen the valves, based purely on judgment of the human factors aspects.

Putting these factors together, the AFW failure probability is the product of a 5% probability of inadvertent AFW isolation, a 33% probability that neither valve will reopen on demand, and a 10% probability that manual opening will not be attempted or will fail to be accomplished in time. The product is 1.7×10^{-3}/demand. In addition, no solution is perfect. We will assume that any resolutions adopted will be at least 90% effective. Thus, the change in AFW failure probability will be on the order of 1.5×10^{-3}. The change in core-melt frequencies can now be estimated. The cut sets are:

$T_1M^*LOPNRE^*\Delta L^*U$	3×10^{-7}/RY
$T_2M^*\Delta L^*U$	1.5×10^{-5}/RY
$T_3^*M^*PCSNR^*\Delta L^*U$	1.5×10^{-7}/RY
Total ΔF =	1.5×10^{-5}/RY

Under the assumption that one plant will find and correct the problem, the core-melt frequency is 1.5×10^{-5}/year.

Consequence Estimate

Normally, accident sequences such as the ones discussed in the previous section would be distributed across a spectrum of containment failure modes in a variety of ways. However, because the sequences of interest here are similar in their final stages prior to core-melt, all three sequences will be distributed across the containment failure modes in the same manner.

All three principal accident sequences involve a core-melt with no large breaks initially in the reactor coolant pressure boundary. The reactor is likely to be at high pressure (until the core melts through the lower vessel head) with a steady discharge of steam and gases through the PORV. These are conditions likely to produce significant hydrogen generation and combustion.

The Zion and Indian Point PRA studies used a 3% probability of containment failure due to hydrogen burn (the "gamma" failure). We will follow this example and use 3%, remembering that specific containment designs may differ significantly from this figure. In addition, the containment can fail to isolate (the "beta" failure). Here, the Oconee PRA[889] figure of 0.0053 will be used. If the containment does not fail by isolation failure or hydrogen burn, it will be assumed to fail by base mat melt-through (the "epsilon" failure).

Using the usual prioritization assumptions of a central midwest plains meteorology, a uniform population density of 340 persons per square mile, a 50-mile radius and no ingestion pathways, the consequences are:

Failure Mode	Percent Probability	Release Category	Consequences (man-rem)
gamma	3%	PWR-2	4.8×10^6
beta	0.5%	PWR-5	1.0×10^6
epsilon	96.5%	PWR-7	2.3×10^3

The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem.

The consequence estimate is 50 man-rem/reactor. On the average, the B&W and CE plants have about 31 calendar-years of licensed lifetime remaining per plant. This is roughly 24 years of operational life. Based on the above assumption that one plant will find and correct the problem, the risk reduction estimate is 50 man-rem.

Cost Estimate

Industry Cost: The costs associated with resolving this item depend on the nature of the solution. A check of the valve operator design is relatively inexpensive. A test to ensure the valves will open will cost significantly more. Finally, if valve operators are found to be insufficiently sized, the cost of replacement will be higher still. In addition, improvements in maintenance may also be required.

For prioritization purposes, we will assume that a check of design (rather than extensive testing) will be done, and that one plant will be found where the valves would not re-open with a significant differential pressure present. We will assume further that the motor is strong enough to open the valve and that the problem can be fixed by changing torque limit and bypass switch setpoints. Because maintenance error is a relatively minor contributor, we will (for now) not address the issue of improved maintenance.

<u>NRC Cost</u>: For each plant affected, 2 staff-weeks should be sufficient to check the valve design. For the (hypothetical) plant where a problem is found, 6 staff-months should suffice to find a solution. Finally, 6 staff-months plus 2 staff-weeks/plant of NRC time will probably be necessary to impose the requirement. Thus, for 17 plants, the total cost will be roughly $240,000, assuming that a staff-year costs $100,000.

Value/Impact Assessment

Based on a potential risk reduction of 50 man-rem and a cost of $0.24M, the value/impact score is given by:

$$S = \frac{50 \text{ man-rem}}{\$0.24M}$$
$$= 208 \text{ man-rem}/\$M$$

Other Considerations

1. There is no significant ORE associated with the fix for this issue. The valves in question are not exposed to contaminated fluids, since they are in the secondary system.

2. There are offsetting savings which could be credited against the expenditures above. The cost of a core-melt would be about a billion dollars plus replacement power for the rest of the plant lifetime. In an actuarial sense, using the accident frequency estimated above and assuming a 5% annual discount rate, this corresponds to a present worth of about $430,000/plant. Also, even if core-melt is avoided and if the plant is ever placed in a situation where feed-and-bleed techniques are used, major cleanup will be necessary because of rupture of the quench tank. If cleanup lasts 6 months, the present worth cost is about $770,000/plant.

   Finally, it should be noted that the Davis-Besse event kept the plant shut down for over three months. The frequency of this situation is about 1.2×10^{-2}/RY, which corresponds to an actuarial cost of roughly $4.6M/plant.

   Obviously, if any of these three considerations were included, the cost-benefit ratio would be favorable indeed. It would be very much in the licensee's financial interest to fix this problem.

3. The figures assume that the feed-and-bleed failure probability is 0.015. In actual fact, NUREG-1154[886] gives the impression that the Davis-Besse operators were rather reluctant to initiate feed-and-bleed. Thus, this figure may be somewhat optimistic. Also, some (CE) plants do not have power-operated relief valves on the primary system and thus cannot use feed-and-bleed techniques.

4. Some plants operate with the AFW isolation valves in the closed position. Thus, these plants will not need an inadvertent isolation to encounter a problem. On the other hand, these plants are more likely to be designed to open under differential pressure or to find the problem by normal testing.

5. The discussion has addressed only PWRs; BWRs have analogous systems (HPCI and RCIC) for mitigating loss-of-feedwater events. Moreover, these systems have normally-closed motor-operated isolation valves in the discharge line. But these valves are tested during normal system testing. In addition, BWRs can rapidly depressurize via the ADS and can use low pressure systems for decay heat removal.

6. An OIE Bulletin on the subject of valve operability is being considered. This may well be sufficient to resolve the issue for most plants. However, some followup action may be appropriate particularly for plants where the viability of feed-and-bleed is doubtful. If such a plant were also susceptible to the common-mode valve problem described here, the core-melt frequency could approach 1×10^{-3}.

7. This issue is related to Item II.E.6.1, "In-Situ Testing of Valves." Although II.E.6.1 is also concerned with valve operability, this new item differs in that the potential for commonality is a primary concern. Item II.E.6.1 is geared toward the single failure rate per valve, not the potential for common-mode failures, but is not specific as to which valves or which failure mode.

8. This issue is also similar to Issue 87 which concerns the failure of the HPCI steam line isolation valves to close following a break in the line downstream of the valves. These failures are also due to a design problem in which the valve may not have been designed to operate under some overlooked conditions. There may be other systems with valves that are not designed to operate under all likely conditions and therefore a widening of the scope of this issue may be in order.

9. It was assumed that the probability of both AFW isolation valves failing to reopen was 33%. In some cases (e.g., undersized actuators), this figure may be nearly 100%, which would triple the priority parameters. However, this would change no conclusions.

CONCLUSION

Based on the change in core-melt frequency, this issue was given a high priority ranking, but was later integrated into the resolution of Issue 124.

ITEM 122.1.B: RECOVERY OF AUXILIARY FEEDWATER

DESCRIPTION

Historical Background

This item addresses Findings 4, 8, and 15 in Sections 5.2.4 and 6.2.4 of NUREG-1154.[886] The particular issue deals with a potential inability to remove reactor decay heat due to the second common mode failure discussed above. This is the excessive delay in recovery of auxiliary feedwater due to difficulty in restarting AFW pump steam turbines, if the turbines are tripped.

Safety Significance

Some method of decay heat removal is necessary within 30 minutes after the start of this type of transient in order to prevent core uncovery. The turbines tripped about 7 minutes into the event. Thus, 23 minutes were available. Although it only took 4.5 minutes for a pair of equipment operators to go to the AFW pump rooms and start work, considerable difficulty was experienced in resetting and restarting the turbines. Thus, it might well have taken longer than 23 minutes to get the AFW pumps in operation. Had other decay heat removal techniques (i.e., startup feed pump and primary side feed-and-bleed) also failed, core damage would have resulted.

This issue is applicable to any PWR. However, it is of greatest importance to plants with only steam-driven AFW trains (such as Davis-Besse) and of less importance to plants with one steam-driven train plus one or two motor-driven trains. In addition, non-B&W plants are less susceptible because of their greater water inventory in the steam generators which provides more time before active means of decay heat removal are essential. Davis-Besse is the only remaining plant with only steam-driven auxiliary feedwater. Thus, this analysis will be geared to the next-most-susceptible plant class: a B&W plant with one steam-driven and one motor-driven AFW train.

Possible Solutions

The Davis-Besse event exhibited two problems that led to delay in AFW restart. The first problem was that the turbine overspeed trips had to be manually reset requiring plant personnel to be dispatched to the AFW pump rooms. A possible solution is to make the trip resettable from the control room. The trip mechanism is usually a latch hook device on the trip-and-throttle valve. A mechanical device will unlatch the hook and trip the turbine at a preset speed (usually 125% of rated). Other signals can be used to trip the latch hook by means of an electrical solenoid. In either case, the hook must be reset manually. The solution, which has been implemented on some BWR RCIC turbines, is to wire the protective circuits into the throttle mechanism rather than the trip solenoid. The mechanical overspeed trip remains active, but is supplemented by an electrical overspeed trip (set at 110%) which can be remotely reset.

The second problem was that the two equipment operators were unsuccessful in their attempts to get the turbines running and were saved by the arrival of an experienced operator. The most obvious solution to this problem would be to require the plant operators to practice going through the procedures of resetting and starting the turbines, assuming a remote reset is not provided. "Hands-on" practice of this task is not now part of operator training.

PRIORITY DETERMINATION

Frequency Estimate

Problem 1: The affected sequences and cut sets are the same as those for Item 122.1.A except parameter ΔL, the change in AFW failure probability to be attributed to this item. This is governed by three factors: the probability of a resettable turbine trip, the probability of failure to manually reset and restart the turbine, and the probability of failure (in this study) of the one motor-driven AFW train.

First, we must estimate the probability of a turbine trip either during the auto-start or while running. PRA fault trees model individual components and their failures, but do not normally model the trips of spurious and/or readily resettable trips of concern here. Thus, PRA fault-tree-based estimates are really estimates of the failure rate assuming that the manual reset problem has been fixed. (Also, the turbine-train-only failure rate is remarkably difficult to separate out of most PRA studies.) We will use a value of 3×10^{-2} failure/demand, based on the station blackout calculations for a two-train AFW system in an RRAB memorandum.[894]

In NUREG/CR-2098,[893] 112 of the 170 AFW events tabulated were failures of turbine rather than motor-driven pumps. Of the 112 turbine events, 40 were trips, usually on overspeed. Thus, given a failure of a turbine-driven AFW pump to operate, there is a 35% chance that a (manual) reset might recover the pump. Therefore, the failure rate before fixing is $(3 \times 10^{-2})(1.35)$/demand or (4.1×10^{-2})/demand.

We must now estimate the change in turbine failure rate due to elimination of the need for manual reset. In the Davis-Besse event, the operators were able to reset the two turbines in 4.32 and 4.77 minutes (but not get them running), which was about one-fifth of the 23.4 minutes available before core uncovery.[886]

One would expect that, for a straightforward task such as resetting and restarting a turbine, the time needed would be described by a reasonably symmetrical distribution centered about an average time. Here, the 4.5-minute average time of the two unsuccessful resets at Davis-Besse is probably a reasonable estimate of a general mean time for an experienced operator to successfully complete the task. This number is also consistent with oral communications we have had with operations staff at two other plants and with a walk-through of the procedure at Davis-Besse by NRC staff. However, we have no direct information about the width of the distribution--the minimum and maximum time needed for completion. Thus, we will use a pragmatic approach. We will keep the peak of the distribution at 4.5 minutes and fix it at zero at time equals zero. Further, we will use the single-event Poisson distribution which will extend out to infinity in the positive direction. The formula is $P(t) = \lambda t \exp(-\lambda t)$

The peak of the distribution is at $t = 1/\lambda$ so we will use $\lambda = 1/4.5$ minutes = 0.22. The probability of not resetting the turbine before 23.4 minutes is obtained by integrating this formula from 23.4 minutes to infinity. The integral is:

$$\begin{aligned} P(t > t_o) &= (1 + \lambda t_o) \exp(-\lambda t_o) \\ &= 0.036 \\ &= 3.6\% \end{aligned}$$

Again, this approach is pragmatic rather than rigorous--the formula is appropriate for randomly distributed events, which this really is not. In the actual event at Davis-Besse, it is evident that the operating crew worked as fast as they could. It is also evident that the task of resetting and restarting the turbines was far from smooth; many things went wrong. Moreover, things might well not be easy and straightforward in another similar event. Nevertheless, a factor of five margin in the time actually taken is significant. Thus, 3.6% does not seem unreasonable in spite of the rather sparse mathematical basis.

In addition, there is a finite probability that plant operators will encounter difficulty in moving through the plant and entering the AFW pump rooms due to locked doors, etc. To account for this, we will add a 1% probability of an insurmountable difficulty in reaching the turbines (based on the calculations in Issue 122.3) to get a total probability of failure to reset of 0.046.

ΔL can now be estimated. First, the change in the turbine-driven train's failure rate is:

$$\left[\frac{4.1 \times 10^{-2}\ \text{failures}}{\text{demand}}\right]\left[\frac{0.35\ \text{turbine trips}}{\text{Total failures}}\right]\left[\frac{0.046\ \text{failure to reset}}{\text{Turbine trip}}\right]$$

$$= 6.6 \times 10^{-4}/\text{demand}$$

In addition, we must estimate the unavailability of the motor-driven train. The RRAB memorandum[894] gives a "typical" AFW system unavailability of 10^{-3}/demand for a two-train system. Such a figure includes common-mode failures and common component failures in addition to the individual train failures. For our purposes, we will assume that the common-mode and common-component contributions are small and thus the turbine train contribution enters as a multiplicative factor. The non-turbine failure rate is then $10^{-3}/(3 \times 10^{-2})$ or 0.033.

Giving credit for the motor-driven train, if AC power is available,

$$\Delta L = (6.6 \times 10^{-4})(0.033) = 2.2 \times 10^{-5}$$

If AC power is not available,

$$\Delta L' = 6.6 \times 10^{-4}$$

One more figure is needed. Since the turbine-driven AFW pump is especially significant for loss of all AC power (station blackout), a diesel unavailability is needed. NUREG-1032[890] gives a range of 1.1×10^{-3} to 6.8×10^{-3} for a one-out-of-two diesel configuration. We will use 2.7×10^{-3}, the middle of this range.

Cut sets can now be calculated:

$T_1M^*LOPNRE^*\Delta L^*U$	4.1×10^{-9}/RY
$T_1M^*LOPNRE^*DIESELS^*\Delta L'$	2.0×10^{-8}/RY
$T_2M^*\Delta L^*U$	2.1×10^{-7}/RY
$T_3^*M^*PCSNR^*\Delta L^*U$	2.1×10^{-9}/RY
Total ΔF =	2.4×10^{-7} core-melt/RY

For 9 PWRs with two-train AFW systems, this frequency is 2.2×10^{-6} core-melt/year.

Problem 2: In the first problem, it was assumed that the only question was the time available for a qualified operator to locally reset a tripped AFW turbine. The fact that neither of two equipment operators was able to get the turbines running at Davis-Besse strongly suggests that the probability of failure is nearly unity over the course of a half-hour, if the individuals involved have never performed this task before. (This task is generally not part of an operator's training.) In general, during off-shifts, experienced personnel are present in very limited numbers. In a future event, the more experienced personnel are likely to be busy with other tasks (e.g., getting diesels started), and a less experienced operator may once again be faced with the task of resetting and restarting AFW turbines.

This second problem is not amenable to the exponential time calculations of Problem 1, since the average time needed for inexperienced personnel is likely to be far in excess of 30 minutes. Thus, we will arbitrarily assume that, should an event occur during the evening, night, or weekend shifts (76% of the time), there is a 50% probability that an AFW turbine trip reset will be assigned to an inexperienced operator who is at most 10% likely to succeed in getting the turbine running in the required time. Thus, the change in the probability of failure to restart the turbine becomes (0.76)(0.50)(0.90) = 0.342.

For this problem, the change in the turbine-driven train's unavailability is:

$$\left[\frac{4.1 \times 10^{-2} \text{ failure}}{\text{demand}}\right]\left[\frac{0.35 \text{ turbine trip}}{\text{failure}}\right]\left[\frac{0.046 \text{ failure to restart}}{\text{turbine trip}}\right]$$

$$= 4.9 \times 10^{-3}/\text{demand}$$

Giving credit for the motor-driven train as before:

$$\Delta L = (4.9 \times 10^{-3})\,(0.033) = 1.6 \times 10^{-4} \quad \text{(AC power available)}$$
$$\Delta L' = 4.9 \times 10^{-3} \quad \text{(AC power not available)}$$

Cut sets can now be calculated:

$T_1M^*LOPNRE^*\Delta L^*U$	3.1×10^{-8}
$T_1M^*LOPNRE^*DIESELS^*\Delta L'$	1.7×10^{-7}
$T^2M^*\Delta L^*U$	1.6×10^{-6}
$T^3{}^*M^*PCSNR^*\Delta L^*U$	1.6×10^{-8}
Total ΔF =	1.8×10^{-6} core-melt/RY

For 9 PWRs with two-train AFW systems, this frequency is 1.6×10^{-5} core-melt/year.

Consequence Estimate

The consequence estimate is the same as that for Item 122.1.A. The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem. The 9 PWRs with two-train AFW systems have about 250 calendar-years of collective license lifetime remaining. This is roughly 189 years of operational life.

Problem 1: The consequence estimate is $(2.4 \times 10^{-7})(1.5 \times 10^{5})(189)$ man-rem = 7 man-rem.

Problem 2: The consequence estimate is $(1.8 \times 10^{-6})(1.5 \times 10^{5})(189)$ man-rem = 51 man-rem.

Cost Estimate

Problem 1: Changing the turbine trip logic on a safety-related system is likely to require 6 staff-months of effort per plant, even if no major procurement is needed. In addition, at least 3 staff-months of generic work plus a week of effort on each plant will be required of the NRC staff. The total cost for the 9 PWRs with 2 AFW trains (excluding Davis-Besse) is thus at least $0.5M.

Problem 2: Having operators practice the task of resetting and manually starting AFW turbines is relatively inexpensive. (If, after the first time, more than half an hour of the operator's time is needed, there is little point in the exercise.) However, this is a continuing expense. We will assume one staff-month/plant of administrative effort to set the program up plus two staff-weeks/year thereafter of actual practice. Assuming a 5% discount rate and an average remaining life of 28 calendar-years, this is about $620,000 total for 9 plants. NRC costs are again likely to be one staff-month of generic work plus 1 staff-week/plant, or about $26,000. The total cost is roughly $650,000.

Value/Impact Assessment

Problem 1

The value/impact score is given by:

$$S = \frac{7 \text{ man-rem}}{\$0.5M}$$

$$= 14 \text{ man-rem/\$M}$$

Problem 2

The value/impact score is given by:

$$S = \frac{51 \text{ man-rem}}{\$0.65M}$$

$$= 78 \text{ man-rem/\$M}$$

Other Considerations

1. There is no significant ORE associated with the fix for this issue. The valves in question are not exposed to contaminated fluids, since they are in the secondary system.

2. There are offsetting savings which could be credited against the expenditures above. The cost of a core-melt would be about $1 billion plus

replacement power for the rest of the plant lifetime. In an actuarial sense, using the accident frequencies estimated above and assuming a 5% annual discount rate, this corresponds to a present worth or $6,000/plant.

Also, even if a core-melt is avoided and the plant is ever placed in a situation where feed-and-bleed techniques are used, major cleanup will be necessary because of rupture of the quench tank. If cleanup lasts six months, the actuarial cost has a present worth of $10,000/plant.

3. The figures assume that the feed-and-bleed failure probability is 0.015. In actual fact, NUREG-1154[886] gives the impression that the Davis-Besse operators were rather reluctant to initiate feed-and-bleed.

   Thus, this figure may be somewhat optimistic. Also, some (CE) plants do not have power-operated relief valves on the primary system and thus cannot use feed-and-bleed techniques. Raising the feed-and-bleed failure probability to 0.1 would put this issue into the high priority range.

4. Some plants may have still other means of decay heat removal (e.g. the high head service water system at Oconee). For these plants, the figures would have to be adjusted downward.

5. These figures should not be used for BWR HPCI and RCIC systems. The BWR systems generally have a greater number of trips and an elaborate isolation system.

6. The calculations above are based on an AFW system with one motor-driven and one turbine-driven train. A plant such as Davis-Besse with only two turbine-driven trains will be significantly more susceptible to this issue because whatever tripped the first turbine may well trip the second also. Other plants which originally were equipped with only turbine-driven trains include Turkey Point 3 and 4 and Haddam Neck. The Turkey Point units share three turbine-driven AFW trains and also have each installed a motor-driven train. Haddam Neck has two turbine-driven trains and has installed one (manual start) motor-driven train. The availability and surveillance requirements for the new motor-driven trains on these plants have not been added to the plants' technical specifications and they are as yet not capable of being powered from onsite emergency power. Nevertheless, given the presence of these diversely powered trains, these plants are not likely to need special treatment for this issue.

CONCLUSION

This issue is of high priority for those plants which cannot remove decay heat by feed-and-bleed or other alternative means and should be subsumed into Issue 122.2 for such plants. Based on the calculations above, the remaining part of the issue was placed in the medium priority category, but was later integrated into the resolution of Issue 124.

ITEM 122.1.C: INTERRUPTION OF AUXILIARY FEEDWATER FLOW

DESCRIPTION

Historical Background

This item addresses Finding 6 in Section 5.2.2 of NUREG-1154.[886] The particular issue deals with a potential inability to remove reactor decay heat because of the interruption of all auxiliary feedwater flow due to the first common mode failure discussed above. This is the closing of the AFW pump discharge isolation valves. This is related to Issue 122.1.A, which deals with another problem that prevented the isolation valves from reopening.

Safety Significance

The definition[885] of this issue is ambiguous in that the full title, "Interruption of Auxiliary Feedwater Flow due to Failures in Steam and Feed Line Break Accident Mitigation Features (e.g., SFRCS)," refers to the second failure described under 122.1, but the bases presented are Section 5.2.2 and Finding 6 of NUREG-1154[886] which refer to the first failure (i.e., of main, not auxiliary, feedwater). We will address both in this analysis.

The first sub-issue is the spurious closure of the MSIVs, in this case as a result of a turbine trip. Most plants of recent design are equipped with turbine-driven main feedwater pumps. Closure of the MSIVs will shut off all feedwater flow. Moreover, once MSIVs are closed, the reopening of these valves is a rather elaborate procedure. The loss of main feedwater is not easily recoverable.

The second subissue is the isolation of auxiliary feedwater. This is done in the event of a steam line break within containment to prevent exceeding the containment design pressure. The containment is designed to accommodate the initial blowdown of a steam generator. If feedwater to the affected steam generator is not shut off, the boil-off due to decay heat will continue to dump steam to the containment. However, in a transient involving loss of main feedwater but no steam line break, shutting off AFW flow is very undesirable. It must also be remembered that loss-of-feedwater events are far more frequent than steam line breaks.

Possible Solutions

Inadvertent MSIV closure has in the past been considered a relatively rare transient. In the particular case of the Davis-Besse transient, the steam generator level sensors had been replaced by a new type of transmitter.[886] The rapid closure of the turbine stop valves sent a pressure wave up the steam lines back to the steam generators. This phenomenon is not new; it is routinely allowed for in the analysis of BWR transients where the reactor core is directly sensitive to the pressure pulse. However, the new transmitters were of a design that did not dampen out the pressure pulse, which cased them to trip. A possible solution would be to add some damping to the level signal at those plants where this has proven to be a problem.

The inadvertent isolation of AFW flow appears to be primarily a human factors problem associated with the controls layout. This could be solved by a redesign of this portion of the control panel. If on further study it appears that spurious isolations are occurring because of hardware problems, other actions (e.g., possibly using high containment pressure in a logical "and" with low steam generator pressure) might be necessary. In addition, the question of whether an operator should anticipate automatic actuations or simply observe and confirm them should be addressed in the long term.

This item appears to be associated with B&W plants. The isolation logic and AFW control is quite different for the other PWR vendors. (CE-designed plants may be susceptible to the first subissue.)

PRIORITY DETERMINATION

Frequency Estimate

The affected sequences and cut sets are the same as those for Item 122.1.A with the exception of the parameter L which is redefined as follows:

L - This is the failure rate of the auxiliary feedwater system. The RRAB memorandum[894] gives 10^{-3}/demand as "typical" for a two-train system (offsite power available) and 1.8×10^{-5}/demand as "typical" for a three-train system.

The first subissue, inadvertent MSIV closure, has the effect of turning the T_3-initiated transients into T_2-initiated transients. (T_1 transients are unaffected). If every transient led to MSIV closure (as NUREG-1154,[886] Section 5.11 seems to imply), the parameters and sequences are straightforward:

$\Delta T_2 = (5.7 - 0.64) = 5.06$

$\Delta T_3 = -5.7$

For plants with a two-train AFW system:

$\Delta T_2 M^*L^*U$	7.6×10^{-5}
$\Delta T_3^*M^*PCSNR^*L^*U$	-9.5×10^{-8}
Net change, ΔF =	7.6×10^{-5}/RY

For plants with a three-train AFW system:

$\Delta T_2 M^*L^*U$	1.4×10^{-6}
$\Delta T_3^*M^*PCSNR^*L^*U$	-1.7×10^{-9}
Net change, ΔF =	1.4×10^{-6}/RY

The second subissue, AFW isolation, affects parameter L. The change in L is composed of two factors: the change in the probability of spurious isolation and the probability of failure to reopen on demand. As discussed in issue 122.1.A, we will assume a 5% minimum likelihood of spurious AFW isolation and assume further that another plant with a high (e.g., 20%) likelihood exists.

The second factor is the failure of the isolation valves to reopen on demand. We will assume that Item 122.1.A has been addressed independently and that this failure probability is now governed by the failure of an operator to diagnose and correct the problem. The operator failure rate for such a situation is not independent of the spurious actuation error described above. We will assume, based on judgment, that 95% of the time the operator will correct the error by resetting the inadvertent isolation and reopening the isolation valves.

For the more realistic (5% inadvertent isolation probability situation, the cut sets become:

$T_1M*LOPNRE*\Delta L*U$	4.7×10^{-7}
$T_2M*\Delta L*U$	2.4×10^{-5}
$T_3*M*PCSNR*\Delta L*U$	2.4×10^{-7}

Total $\Delta F \approx 2.5 \times 10^{-5}$/RY

For the more extreme (20%) case, this change in core-melt frequency would be four times this, or 9.9×10^{-5}.

Consequence Estimate

The consequence estimate is the same as that for Item 122.1.A. The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem.

Cost Estimate

The core-melt frequencies are in a range where costs that are within reason will not affect priority assignments. Consequently, no cost analysis has been made.

Value/Impact Assessment

Without a detailed design examination, it is not possible to determine exactly how many plants are affected. The B&W plants have an average of 29.5 calendar-years (22 operational years) of lifetime left. Priority parameters are:

	Subissue 1	Subissue 2
Man-rem/reactor	250	80
Core-melt/RY	7.6×10^{-5}	2.5×10^{-5}

Other Considerations

1. There is no significant ORE associated with the fix for this issue. The valves in question are not exposed to contaminated fluids since they are in the secondary system.

2. The figures assume that the feed-and-bleed failure probability is 0.015. In actual fact, NUREG-1154[886] gives the impression that the Davis-Besse operators were rather reluctant to initiate feed-and-bleed. Thus, this figure may be somewhat optimistic, which would raise the priority scores still higher.

3. The two subissues were evaluated separately above because they involved two separate failures in the Davis-Besse event. Nevertheless, it should be noted that both involved the SFRCS. In essence, one control system apparently has the capability to shut off both main feedwater (by MSIV closure) and auxiliary feedwater. Although two distinct failures were involved at Davis-Besse, there may well be a single failure within the SFRCS which could do both. Deterministic evaluations of this system should recognize the seriousness of such a failure mode.

CONCLUSION

Based on the core-melt frequency figures above, this issue was placed in the high priority category, but was later integrated into the resolution of Issue 124.

ITEM 122.2: INITIATING FEED-AND-BLEED

DESCRIPTION

Historical Background

This issue deals with the adequacy of emergency procedures, operator training, and available plant monitoring systems for determining the need to initiate feed-and-bleed cooling following loss of the steam generator heat sink. It is based upon Findings 10, 17 and 18 in Sections 6.1.1 and 6.1.2 of NUREG-1154.[886] Essentially, the operators were reluctant to take the rather drastic step of initiating feed-and-bleed cooling, probably because they believed restoration of the AFW system was imminent. The fact that feed-and-bleed cooling releases primary coolant to the containment (implying an extensive shutdown for the purpose of decontamination) may also have influenced their actions. Finally, the normal control room instrumentation was inadequate to clearly inform the operators that feed-and-bleed was called for. The SPDS which would have displayed the necessary information was not operable.

The reactor vendors have provided their customers with feed-and-bleed procedures. Feed-and-bleed capability is not currently specifically required by the NRC although the techniques, benefits, and costs were evaluated as part of USI A-45. Basically, feed-and-bleed cooling is a method of last resort which can avert core damage if main and auxiliary feedwater is lost and other methods of decay heat removal are unavailable. For plants licensed without a PORV, the lack of feed-and-bleed capability was a significant issue and the need for a highly reliable AFW system was emphasized.

Safety Significance

PRAs give considerable credit for feed-and-bleed cooling. A failure rate of one or two percent is a typical assumption. However, the Davis-Besse event chronology leaves an impression that this failure probability may be overly optimistic.

In addition, it should be noted that, depending on specific plant design, there may be a fairly short time period in which feed-and-bleed cooling will be successful. If the plant operators delay too long before initiating feed-and-bleed cooling, their error may not be retrievable by later action.

This issue applies to all plants which can use feed-and-bleed techniques. This is all PWRs except for a few CE-designed plants which have no pressurizer PORVs.

Possible Solutions

The solution is a matter of emphasis on safety vs. operation, training in existing procedures, and possibly an upgrading of instrumentation at certain sites. In addition, the procedures themselves could be upgraded to make the criteria for initiation of feed-and-bleed cooling more direct and unambiguous, leaving less room for operator reluctance. (For example, in the case of Davis-Besse, basing the initiation of feed-and-bleed on hot leg temperature rather than on steam generator parameters has been suggested.) Here, we will concentrate on ensuring that existing procedures are followed. The general technical aspects of feed-and-bleed decay heat removal was addressed under USI A-45.

PRIORITY DETERMINATION

Frequency Estimate

The question of interest is, what is the change in core-melt frequency if the failure probability of feed-and-bleed cooling (U) is changed? NUREG/CR-1659[54] and NSAC-60[889] assume a failure probability of 0.015 for non-ATWS sequences (RSSMAP parameter "HPMAN") and 0.10 for the (higher stress) ATWS sequences ("HPMAN1"). The operators' performance during the Davis-Besse event leaves a strong impression that these figures are too low. We will assume, based purely on judgment, that failure probabilities of 0.10 for non-ATWS sequences and 0.50 for ATWS sequences are more reasonable estimates.

In making the calculations, the parameters were the same as in Issue 122.1.A, except:

a. The frequency of loss of main feedwater transients T_2,(momentary and sustained) was set at 2.13/year, based on NSAC-60.[889]

b. The AFW failure probability (L) was set as follows, based on the RRAB memorandum:[894]

	Offsite Power Available	No Offsite Power
3-train AFW	1.8×10^{-5}	5.1×10^{-5}
2-train AFW	1.0×10^{-3}	1.7×10^{-3}

In addition, the computerized RSSMAP[54] analysis was changed as follows:

a. The probability of loss of onsite power (B_3) was changed to 1.3×10^{-3}, a figure more representative of a twin diesel system. (Oconee uses hydroelectric generators for emergency power.)

b. Oconee's capability of feeding the steam generators with the High Head Service Water System was disabled (HHMAN = 1.0).

A series of computer calculations was performed, in an attempt to obtain both the "best" answer and some information as to the sensitivity of the answer to a variety of conditions.

Calculation	ΔF (Core-melt/RY)
3-train AFW system HPMAN raised to 0.1 HPMAN1 raised to 0.5	3.3×10^{-5}
3-train AFW system, HPMAN raised to 0.1 ATWS sequences unchanged	9.2×10^{-6}
2-train AFW system HPMAN raised to 0.1 HPMAN1 raised to 0.5	1.0×10^{-4}
2-train AFW system HPMAN raised to 0.1 ATWS sequences unchanged	8.1×10^{-5}
Test case, original RSSMAP parameters. HPMAN raised to 0.1 ATWS sequences unchanged	2.0×10^{-5}

Clearly, the change in the feed-and-bleed failure probability has a strong effect on core-melt frequency. The figures span the decade from 10^{-5} to 10^{-4}. We will use the first calculation (3.3×10^{-5}) bearing in mind that the figure for a plant with a two-train AFW system will probably be greater. In addition, it should be noted that even a partial solution will make a significant reduction in core-melt frequency.

There are 55 operating PWRs, with an aggregate of about 1700 calendar-years or 1300 operational years of lifetime remaining. Thus, the frequency estimate is $(3.3 \times 10^{-5})(55)$ core-melt/year or 1.8×10^{-3} core-melt/year.

Consequence Estimate

The consequence estimate is the same as that for Item 122.1.A. The "weighted-average" core-melt will have consequences of 1.5×10^{5} man-rem. For 55 plants with a combined remaining operation life of 1300 years, the consequence estimate is approximately 6,500 man-rem.

Cost Estimate

The fix for this issue is likely to be procedural in nature, with upgrades in equipment more likely to be done under USI A-45. We will assume that 6 staff-months/plant will suffice for refresher training on these procedures. NRR costs are likely to be on the order of 6 staff-months of generic effort plus 2 staff-weeks per licensee. For 55 operating PWRs, this is roughly $3M.

Value/Impact Assessment

Based on a risk reduction of 6,500 man-rem and a cost of $3M, the value/impact score is given by:

$$S = \frac{6{,}500 \text{ man-rem}}{\$3M}$$

$$= 2{,}167 \text{ man-rem/\$M}$$

Other Considerations

(1) For a plant with a two-train AFW system, the per-reactor and per-RY figures will be roughly three times as large.

(2) This issue does not involve ORE.

(3) There is an offsetting saving which could be credited against the expenditures above. The cost of a core-melt would be about one billion dollars plus replacement power for the rest of the plant lifetime. In an actuarial sense, using the accident frequencies estimated above, assuming a 5% annual discount rate and subtracting off the feed-and-bleed cleanup costs which would reduce the core-melt costs, this corresponds to about a present worth of $1.2M/plant.

(4) In contrast to the saving associated with averting a core-melt, an unnecessary use of feed-and-bleed will result in major cleanup costs. If half the uses of feed-and-bleed are unnecessary and a cleanup lasts six months, the actuarial cost shows a present worth of roughly $400,000/plant (based on a residual frequency of unnecessary use of feed-and-bleed of 5×10^{-4}/RY).

CONCLUSION

Based on the above calculations, this issue was given a high priority. In resolving the issue, the staff concluded that there was no need for new regulatory requirements/guidance. This conclusion was based on the determination that there is adequate reactor safety and ongoing industry initiatives to continue enhancing safety involving feed-and-bleed. More specifically, the staff's conclusion was based on the following: (1) as a result of the TMI accident, NRC required licensees to have new EOPs to prevent/mitigate accidents; (2) licensees currently have EOPs in place that incorporate NSSS vendor guidance for feed-and-bleed; (3) licensees are continuing to enhance feed-and-bleed procedures taking into account current NSSS vendor recommendations; and (4) NRC has ongoing licensing review/inspection activities concerning NSSS vendor/licensee enhancement of EOPs including feed-and-bleed. Thus, this issue was RESOLVED and no new requirements were established.[1204]

ITEM 122.3: PHYSICAL SECURITY SYSTEM CONSTRAINTS

DESCRIPTION

Historical Background

This particular issue arose out of Finding 9 in Section 3.6 of NUREG-1154,[886] which states:

> "The locked doors and valves in the plant had the potential for significantly hampering operator actions taken to compensate for equipment malfunctions during the event and were a significant concern to the equipment operators."

In the Davis-Besse event, the operators were able to reach the AFW pump room with no reported difficulty. There were difficulties in resetting and restarting the turbines and in opening the isolation valves, but these were not related to locking devices.

Safety Significance

Barriers and locks are present for purposes of physical security, as the title of this issue implies. In addition, barriers are provided for other purposes, such as personnel protection, fire zone isolation and flood protection. Valves are locked not only for security reasons, but also because inadvertent opening of these valves may have economic or safety consequences. The presence of the locking devices and barriers must strike a balance between these purposes and the fact that these devices may impede free movement in the plant and some local operations during an emergency. It should be noted that the control boards in the control room are also liberally supplied with keylock switches. This issue applies to all reactors.

Possible Solution

The possible solution for this issue is to completely evaluate the net effect of a given barrier on plant safety and either remove it or (in extreme cases) provide an alternate means of entrance (with its own locks), should the analysis so indicate.

PRIORITY DETERMINATION

This issue is not new; the impact of locked doors and barriers on safety was evaluated in Issue 81 considering the frequency of a need for entry into the plant, the likelihood of procedural error (e.g., wrong key), and the probability of successful forcible entry in a timely fashion.

Issue 81 considered only non-security barriers. A barrier that was installed for security reasons is not as likely to be forcibly penetrated in a few minutes. Moreover, the scenario here is slightly different than that of Issue 81. It should be noted, however, that the Davis-Besse experience confirms some of the assumptions of the Issue 81 evaluation since there were in fact no problems with locked doors or valves.

Frequency Estimate

We will estimate frequency based on a loss of main feedwater event consistent with Issue 122.1.A. The frequencies and probabilities are: non-recoverable loss of main feedwater (0.67/RY), failure of auxiliary feedwater (use 10^{-3} for a "typical" two-train system and 1.8×10^{-5} for a "typical" three-train system), and failure of feed-and-bleed cooling (0.015).

We will further assume that a locked barrier may prevent entry into the auxiliary feedwater pump room(s) and that such entry could recover the AFW system. This is a high stress situation. Thus, we will assume that there is a 10% chance of human error (e.g., wrong key) and a 10% chance of non-recovery. (The chance of mechanical lock failure estimated in Issue 81 is 0.001.) We will not assume credit for forcible penetration.

We will not consider the padlocks and chains on the valve wheels, in view of the existence of bolt cutters and the fact that there will be two or three redundant trains. The result is a change in core-melt frequency of 10^{-7} for plants with 2 AFW trains and 1.8×10^{-9} for plants with 3 AFW trains.

Consequence Estimate

The consequence estimate is the same as that for Item 122.1.A. The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem. Assuming 30 years of remaining operational life for plants with 2 AFW trains, the consequence estimate is $(10^{-7})(1.5 \times 10^5)(30)$ man-rem/reactor or approximately 0.45 man-rem/reactor. For plants with 3 AFW trains, the consequence estimate is $(1.8 \times 10^{-9})(1.5 \times 10^5)(30)$ or approximately 0.01 man-rem/reactor.

Cost Estimate

Issue 81 estimated a one-time evaluation of existing locked doors to cost $200,000. We will use this as a minimum per-plant cost, recognizing that an adverse finding will incur labor and equipment costs that may be much larger.

Value/Impact Assessment

2 AFW Trains

Based on a risk reduction of 0.45 man-rem/reactor, the value/impact score is given by:

$$S = \frac{0.45 \text{ man-rem/reactor}}{\$0.2\text{M/reactor}}$$

$$= 2.25 \text{ man-rem/\$M}$$

3 AFW Trains

Based on a risk reduction of 0.01 man-rem/reactor, the value/impact score is given by:

$$S = \frac{0.01 \text{ man-rem/reactor}}{\$0.2\text{M/reactor}}$$

$$= 0.05 \text{ man-rem/\$M}$$

Other Considerations

The analysis is based on the PWR design. It is not expected that a BWR design would be greatly different from that of a three AFW-train PWR, given the ability of HPCI, RCIC, and the ADS low-pressure ECCS to mitigate transients.

CONCLUSION

Based on the above calculations, this issue was given a LOW priority ranking.

REFERENCES

54. NUREG/CR-1659, "Reactor Safety Study Methodology Applications Program," U.S. Nuclear Regulatory Commission, 1981.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission.

885. Memorandum for H. Thompson from D. Crutchfield, "Potential Immediate Generic Actions as a Result of the Davis-Besse Event of June 9, 1985," August 5, 1985.

886. NUREG-1154, "Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985," U.S. Nuclear Regulatory Commission, July 1985.

887. Memorandum for T. Speis from H. Thompson, "Short Term Generic Actions as a Result of the Davis-Besse Event of June 9, 1985," August 19, 1985.

888. Memorandum for H. Denton from T. Speis, "Adequacy of the Auxiliary Feedwater System at Davis-Besse," July 23, 1985.

889. NSAC-60, "A Probabilistic Risk Assessment of Oconee Unit 3," Electric Power Research Institute, June 1984.

890. NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Draft) May 1985.

891. Letter to T. Novak (NRC) from R. Crouse (Toledo Edison Company), December 31, 1981.

892. NUREG/CR-2770, "Common Cause Fault Rates for Valves," U.S. Nuclear Regulatory Commission, February 1983.

893. NUREG/CR-2098, "Common Cause Fault Rates for Pumps," U.S. Nuclear Regulatory Commission, February 1983.

894. Memorandum for O. Parr from A. Thadani, "Auxiliary Feedwater System - CRGR Package," November 9, 1984.

1204. Memorandum for V. Stello from T. Murley, "Final Resolution of Generic Issue (GI) 122.2, 'Initiating Feed and Bleed,'" April 26, 1989.

ISSUE 124: AUXILIARY FEEDWATER SYSTEM RELIABILITY

DESCRIPTION

In 1985, operating experience as well as staff and industry studies indicated that AFW systems continued to fail at a high rate. These studies also indicated that plants with similar AFW system reliabilities (as calculated in accordance with the SRP[11] guidance) did not necessarily exhibit similar AFW system availabilities. Based on these studies and on engineering judgment, the staff concluded that the PWR AFW system reliabilities calculated in accordance with the SRP[11] guidance may have represented the relative reliability of AFW system hardware configurations for various plants, but did not represent the real availability of these crucial safety systems.[914]

In order to ascertain a high level of AFW system reliability and availability, the staff proposed a requirement that all operating plants demonstrate by PRA that their AFW systems had a minimum reliability of 10^{-4} unavailability/demand after accounting for: AFW system support systems, common cause failures, or operator errors. As input to the PRAs, each utility was expected to use its plant-specific data, if available. It was believed that such plant-specific data would reflect design faults, poor maintenance practices, and inadequate testing and surveillance and would indicate how well a particular plant was being operated, thereby identifying those plants that needed improvements.

The following issues were integrated into the resolution of Issue 124:

(1) Issue 68, "Postulated Loss of Auxiliary Feedwater System Resulting from Turbine-Driven Auxiliary Feedwater Pump Steam Supply Line Rupture"

(2) Issue 122.1.a, "Failure of Isolation Valves in Closed Position"

(3) Issue 122.1.b, "Recovery of Auxiliary Feedwater"

(4) Issue 122.1.c, "Interruption of Auxiliary Feedwater Flow"

(5) Issue 125.II.1.b, "Review of Existing AFW Systems for Single Failures."

CONCLUSION

Because of the significance of the AFW system in reducing core-melt frequency, the staff determined that all PWRs should meet the reliability criterion specified in SRP[11] Section 10.4.9 which was not applied to reactors in operation at the time this issue was identified. In order to achieve and maintain a high degree of reliability for the AFW system or alternate decay heat removal, the following was completed: (1) PWR licensees and applicants demonstrated, using reliability analyses, that their AFW systems were of high reliability (10^{-4} to 10^{-5} unavailability/demand); and (2) the staff reviewed the reliability analyses and/or any necessary system modifications and procedural or maintenance changes. As a result of (1) and (2) above, the staff determined whether it was necessary to require that plants upgrade their AFW systems to the safety-related standards. Based on the staff evaluation of the AFW systems of W, CE, and B&W plants (NUREG-0611,[93] NUREG-0635,[95] B&W plant SERs), the staff initially determined that the AFW system of the following plants were not sufficiently reliable and should be upgraded: Prairie Island 1, Prairie Island 2, ANO-1, ANO-2, Fort Calhoun, Crystal River, and Rancho Seco.

In resolving this issue, the staff concluded that substantial improvement in plant safety could be achieved by provision of an additional means of water supply, e.g., startup feedpump, to the steam generators. The staff determined that the two-pump AFW systems at ANO-2 and Rancho Seco needed to be upgraded and took the necessary steps to inform the affected licensees of this decision. Thus, this issue was RESOLVED and requirements were issued to two plants.

REFERENCES

11. NUREG-0800, "Standard Review Plan," U.S. Nuclear Regulatory Commission.

93. NUREG-0611, "Generic Evaluation of Feedwater Transients and Small-Break Loss-of-Coolant Accidents in Westinghouse Designed Operating Plants," U.S. Nuclear Regulatory Commission, January 1980.

95. NUREG-0635, "Generic Assessment of Small Break Loss-of-Coolant Accidents in Combustion Engineering Designed Operating Plants," U.S. Nuclear Regulatory Commission, January 1980.

914. Memorandum for H. Thompson and T. Speis from R. Bernero, "Request for Comments on Draft CRGR Package with Requirements for Upgrading Auxiliary Feedwater Systems in Certain Operating Plants," October 3, 1985.

1203. Memorandum for V. Stello from T. Murley, "Plant-Specific Backfit for Improved Auxiliary Feedwater System Reliability at Arkansas Nuclear One, Unit 2 and Rancho Seco," January 31, 1989.

ISSUE 125: DAVIS-BESSE LOSS OF ALL FEEDWATER EVENT OF JUNE 9, 1985 - LONG TERM ACTIONS

On June 9, 1985, Davis-Besse had a partial loss of feedwater while operating at 90% power. Following a reactor trip, the loss of all feedwater occurred. The two OTSGs became dry and were ineffective as a heat sink. Consequently, the RCS pressure increased indicating a lack of heat transfer from the primary to secondary coolant systems. The PORV automatically opened and closed twice during the event upon reaching the approximate pressure setpoints; it opened a third time, but did not close for some unknown amount of time. The delayed response to close the third time aggravated the recovery of the event and allowed a rapid depressurization of the RCS.

In addition to the short-term actions identified and addressed in Issue 122, a staff report on the event was published in NUREG-1154[886] and an EDO memorandum[895] identifying 29 NRR action items was issued on August 5, 1985. These items became known as long-term generic actions and, in November 1985, were forwarded by DL to DST for prioritization.[940] The items were broken down into two groups: (I) Issues raised in NUREG-1154 and the EDO memorandum; and (II) Other Issues. These 29 items are prioritized separately below and are identified by the numbering system established in the DL memorandum.[940]

ITEM 125.I.1: AVAILABILITY OF THE SHIFT TECHNICAL ADVISOR

DESCRIPTION

Historical Background

This issue was identified as Item 5 in the EDO memorandum[895] and is based on Finding 14 and Section 6.1.3 of NUREG-1154.[886] During the event, neither the shift supervisor nor any of the other licensed operators requested the assistance of the shift technical advisor (STA). One reason for not doing so was the fact that the STA was not in the control room or immediately available when the event occurred, but rather was on an on-call status. (Note: An STA is allowed 10 minutes to reach the control room after being called.) Moreover, the event occurred so rapidly that it was essentially over when the STA did arrive.

STAs were first required as part of the TMI Action Plan Item I.A.1.1, "Shift Technical Advisor." The purpose of the STA was to provide readily available technical support to the plant operators. The STA's expertise was intended to aid in the mitigation of those transients and accidents which involve complex thermal-hydraulic behavior in the primary and secondary coolant systems. In summary, having the STA available was a post-TMI improvement to provide the shift supervisor with additional technical expertise, but his potential assistance and guidance was not available nor required during this event.[886]

Safety Significance

The safety question posed by this issue is whether the STA should be in the control room, or immediately available, to support the shift supervisor rather than being on an on-call status.

CONCLUSION

One year after the Davis-Besse incident, the staff conducted a survey to fulfill a Staff Requirements Memorandum to provide the Commissioners with the implementation results of the Commission Policy Statement on engineering expertise on shift and reported their findings in SECY-86-231.[1023] This survey found that there were only three plants that did not have "on-shift" STAs. On-shift STA means that there is an STA, or an STA-qualified SRO, in or near the control room on a shift basis during operations. The STA shift may or may not correspond to the same shift times and length as the licensed operators' shift. It further means that the STA does not work on an extended assignment period, e.g., 24 hours, during which time the STA is provided quarters to rest during a portion of his extended duty and is available on an on-call basis.

Based on the staff's findings,[1023] STAs are in the control room or immediately available at the majority of operating plants. For the three plants identified with a deficiency, licensee action is being reviewed by the staff on a plant-specific basis. Thus, this item was DROPPED as a generic issue.

ITEM 125.I.2: PORV RELIABILITY

The PORV common to most PWRs (with the exception of CE 3410 and 3800 Mwt plants and ANO-2) is designed to limit system pressure if a transient recovery exceeds the capability of the pressurizer spray system. Davis-Besse has a solenoid-controlled PORV. However, many other PWRs have PORVs that are operated pneumatically (instrument air or nitrogen). Both designs have the same purpose. The PORV is designed to receive an actuation signal to open from the pressurizer pressure instrumentation at a design setpoint (typically 2425 psig) in order to prevent reactor pressure from rising and activating the code safety valves.

If a PORV is used for feed-and-bleed, it can either be: (1) set to stay open by the operator dropping the setpoint low enough such that the valve will remain open until reaching the lower setpoint for LPIS or RHR initiation, or (2) cycled open and closed many times, should there be a need for feed-and-bleed. Option 1 appears to be the more common practice. PORVs are also used in other functions such as mitigating SGTR accidents, LTOP, or RCS venting. Its performance is required for plant protection and accident mitigation.

The following is the evaluation of the four parts of this issue.

ITEM 125.I.2.A: NEED FOR A TEST PROGRAM TO ESTABLISH RELIABILITY OF THE PORV

DESCRIPTION

Historical Background

This issue was identified as Item 9c in the EDO memorandum[895] and is based on Finding 13 and Section 5.2.8 of NUREG-1154.[886]

Safety Significance

Although the PORV can be used successfully in recovering from certain plant transients, there has been no suitable test program established to verify its reliability.[886] This issue affects all PWRs that can use PORVs.

CONCLUSION

The need for improving the reliability of PORVs and block valves, in light of plant protection and accident mitigation requirements, is being addressed in the resolution of Issue 70, "PORV and Block Valve Reliability." Revised licensing criteria may be developed, if needed, to include testing requirements.[896] Therefore, this issue is covered in Issue 70.

ITEM 125.I.2.B: NEED FOR PORV SURVEILLANCE TESTS TO CONFIRM OPERATIONAL READINESS

DESCRIPTION

Historical Background

This issue was identified as Item 9d in the EDO memorandum[895] and is based on Finding 13 and Section 5.2.8 of NUREG-1154.[886]

Safety Significance

The review of the PORV maintenance and operating history reveals that the mechanical operation of the valve had not been tested and that the valve had not otherwise been operated for over 2 years and 9 months prior to the June 9, 1985 event. Therefore, it seems that there exists a need for surveillance tests to confirm operational readiness. This issue affects all PWRs that can use PORVs.

CONCLUSION

The number of times that PORV/Block Valves are used during a typical fuel cycle will be reviewed in the resolution of Issue 70, "PORV and Block Valve Reliability," in order to determine if a surveillance program should be initiated to confirm operational readiness.[896] Therefore, this issue is covered in Issue 70.

ITEM 125.I.2.C: NEED FOR ADDITIONAL PROTECTION AGAINST PORV FAILURE

DESCRIPTION

Historical Background

This issue was identified as Item 9e in the EDO memorandum[895] and is based on Sections 5.2.8 and 6.2.1 of NUREG-1154.[886]

The PORV will receive an actuation signal from pressurizer pressure instrumentation at a design setpoint (typically 2425 psig) to open in order to prevent reactor pressure from activating the code safety valves. After the opened PORV has reduced the pressure sufficiently to reach its closure setpoint (typically 2375 psig), it is sent a signal to close. A simultaneous signal is also sent to the control room indicating to the operator that a close signal was sent to the PORV. PORV closure can be verified by an acoustic monitor installed on the tailpipe downstream of the PORV on all PWRs after the TMI-2 accident. At Davis-Besse, the PORV closure is indicated by a light located on a wall several feet from the operator's control panel. This was available to the operator at Davis-Besse to verify whether the PORV was closed, but was not looked at. Additionally, there is the SPDS, also a post-TMI improvement, that displays a summary of the most safety significant plant status information on a TV screen. Both channels were inoperable prior to the event.[886] This left the operators with only the pressurizer pressure indicator as a source of determining if the PORV was open or closed. Since the indicator appeared steady, the operator assumed that the PORV had closed, but closed the block valve as a precautionary measure. In actuality, however, the PORV had not closed until some time later into the event.

Safety Significance

There have been several stuck open PORVs documented due to a variety of malfunctions some of which were identified to be mechanical failure, broken solenoid linkage, inoperability due to corrosion buildup, and sticking caused by foreign material.[886] As a precaution, the PORV block valve can be closed to insure no LOCA, but this can only be achieved if the operator closes the block valve by remote-manual operation from the control room. In the Davis-Besse event, the operator did close the block valve to prevent a further decrease in pressure and loss of primary coolant through the PORV when it did not reseat.

Possible Solution

Knowing that a stuck-open PORV may result in a potentially dangerous scenario (i.e., LOCA), this issue addresses the concern of whether there is a need for an automatic block valve closure in plants that have PORVs.

Considering available control room indicators such as an acoustic monitor, a reliable SPDS and the operator's acute sensitivity to the PORV's status because of historical events such as TMI-2 and Davis-Besse, another redundant feature (i.e., automating the block valve) would not necessarily result in a significant decrease in core-melt frequency. The acoustic monitor was available to the operator at Davis-Besse; the SPDS was not. However, there is an NRC requirement for the installation of "a concise display of critical plant variables to the control room operators to aid them in rapidly and reliably determining the safety status of the plant."[376]

Additionally, there is a DHFT program underway "to determine the need for and, if necessary, the scope of the NRC's SPDS post-implementation reviews."[900] The information obtained will "allow an assessment of how well the SPDS objectives are being met and provide the basis for an NRC regulatory position on SPDS post-implementation reviews. Following completion of this program DHFT will, if necessary, work with industry to develop appropriate standards for SPDS availability."[900]

The staff performed SARs on the three vendor group responses (CE, B&W, W) to TMI Action Plan Item II.K.3(2), "Report on Overall Safety Effect of Power-Operated Relief Valve (PORV) Isolation System." (References 897, 898, and 899). The SARs included an estimate of core-melt frequency due to a stuck open PORV-induced SBLOCA. The calculations were based on PORV operating data from April 1, 1980 to March 31, 1983 and concluded that post-TMI actions such as lowering the setpoint of the high pressure reactor trip and raising the setpoint of the PORV opening, eliminating the turbine runback feature, and improving operator capability decreased the challenge to the PORV and the probability of a SBLOCA-PORV sufficiently so as not to warrant a requirement for automatic block valve closure.

The Davis-Besse event may be viewed as another "data point" that should be considered in this determination. However, upon consideration of the occurrence of a PORV actuation and the conservative estimates made in the staff's SARs (References 897, 898, and 899), we conclude that the SBLOCA-PORV frequency would still remain within the range of the SBLOCA frequencies given in WASH-1400[16] (10^{-2} to 10^{-4}/RY). The opening of the PORV resulted from a loss of all feedwater to the steam generators and is regarded as a legitimate response and fulfillment of the real purpose for incorporating a PORV into the design. Therefore, the Davis-Besse event does not change the statistics for necessary challenge to the PORV. Consequently, the staff's SARs (References 897, 898 and 899) which concluded that block valve automation is unnecessary are unaffected.

Also it is clear that the automation of the block valve might reduce the initiator (SBLOCA-PORV) frequency, but not necessarily the net core-melt frequency. Since it has the potential for spurious actuation (e.g., spurious electrical signal sensed by the block valve could force it closed during a transient requiring use of the PORV) which would increase core-melt frequency.

The occurrence at Davis-Besse was the result of an initiator already considered in the SARs, i.e., the failure of the AFW system. It was an occurrence that would have resulted in no other outcome should an automatic block valve have been available because the operator closed the block valve himself as a result of his sensitivity to the PORV from post-TMI training.

CONCLUSION

In light of the control room indications available to the operators and the results of the staff SARs (References 897, 898 and 899) that concluded that an automatic PORV isolation system is not necessary, the safety concerns of this issue have been resolved. Thus, this issue was DROPPED as a new issue.

ITEM 125.I.2.D: CAPABILITY OF THE PORV TO SUPPORT FEED-AND-BLEED

DESCRIPTION

Historical Background

This issue was identified in the EDO memorandum[895] and was also raised at an ACRS Subcommittee meeting on Emergency Core Cooling Systems held on July 31, 1985.

Safety Significance

Upon loss of the main and auxiliary feedwater systems, the feedwater flow to the steam generators is insufficient to maintain level. As the level of water in the steam generators decreases, the average temperature of the RCS increases because of the reduced heat transfer from the primary to the secondary coolant systems. When all steam generators are "dry," the plant emergency procedure requires the initiation of makeup/high pressure injection (MU/HPI) cooling of the primary system.[886] This method of decay heat removal is known as "feed-and-bleed" or "bleed-and-feed" depending on the HPI capability of the injection pumps and system design. When this method is initiated, the PORV and high point vents on the RCS, specifically the pressurizer, are locked open breaching one of the plant's radiological barriers and releasing radioactive coolant inside the containment building.[886] MU/HPI is often considered a drastic action because of the radioactive contamination of the containment. Nevertheless, MU/HPI cooling provides a diverse method of core cooling if the main and auxiliary feedwater systems should fail.

This issue is based on an ACRS concern that the PORVs are not qualified for the "hostile" environment in which they are placed when used for feed-and-bleed operation. There are several reasons for this concern. PORVs are usually called upon to respond when all other methods of removing decay heat are not available. The temperature, pressure, and moisture conditions of the containment environment can create a differential thermal expansion of the valve disc and body and may cause the PORV to stick,[886] failing open or closed, or the PORV can close shortly after beginning feed-and-bleed because of short circuits.

CONCLUSION

Under USI A-45, "Shutdown Decay Heat Removal Requirements," the NRC staff is investigating alternative means of decay heat removal in PWR plants using existing equipment or devising new methods. The use of the "feed-and-bleed" procedure is included in this program as well as the need for environmental qualification of the PORV for this method of emergency decay heat removal. Therefore, this issue is covered in USI A-45.[896]

ITEM 125.I.3: SPDS AVAILABILITY

DESCRIPTION

Historical Background

This issue was identified as Item 10c in the EDO memorandum[895] and in a September 19, 1985, DHFS memorandum.[900] The issue addresses the concern as to whether NRC requirements should be revised regarding SPDS availability.

Investigations subsequent to the TMI-2 accident have indicated a need for improving how information is provided to control room operators both during normal and abnormal conditions. TMI Action Plan Item I.D.2, "Safety Parameter Display System (SPDS)," required that licensees install a system to continuously display information from which the plant safety status can be readily assessed. Generic Letter 82-33[376] (Supplement 1 to NUREG-0737) mandated that licensees install an SPDS. Licensee implementation of Item I.D.2 is reviewed and tracked as MPA F-09. The staff requirement imposed on the licensees does not contain specific reliability or availability requirements for the SPDS.

The schedule for operating reactors to meet the requirements of Generic Letter 82-33[376] was proposed to the Commission in SECY-83-484[1037] and formalized in confirmatory orders or licensing conditions. Some plants have incorporated the SPDS implementation into their living schedules; however, other plants have not yet installed the SPDS. Staff actions on MPA F-09 are ongoing to perform NRC post-implementation audits to determine the status of the plants that have installed the SPDS and to modify the schedule for those that have not.

A 1985 survey of six operating plants indicated that two of the plants did not have an operational SPDS although they indicated that they met the requirements of Item I.D.2 (MPA F-09). Three plants were identified as having SPDS availability problems (less than desirable availability). At some of the plants, the SPDS presented potentially misleading information while others suffered from poor operator acceptance or lack of management support.

Recent post-implementation verification inspections have indicated that, of the 37 plants that claimed to have completed the implementation of MPA F-09, less than 1/3 satisfactorily met all the SPDS requirements and were accepted by the NRC staff as operational. Fifty-five plants that claim to have completed the implementation of MPA F-09 have not yet been inspected. Fifteen plants have not yet declared the implementation of the SPDS to be completed and three plants have not yet scheduled the implementation of SPDS.

Safety Significance

Events such as those that occurred at TMI-2, Davis-Besse, Oconee, Rancho Seco, and others may have been less severe if an operable SPDS had been available to the operators. For the Davis-Besse event, "...The inoperability of the SPDS and lack of adequate indications of steam generator conditions contributed to the control room operators not knowing that the steam generators were dry, which, resulted in their failure to follow the appropriate procedures."[886]

The requirements of MPA F-09 indicate that each operating reactor should have a SPDS that will display to operating personnel a minimum set of parameters in order to determine the safety status of the plant during normal and abnormal conditions. It should provide enough information to alert the control room operators who should then verify the information presented by the SPDS before taking any action to avoid a degraded core event. The parameters should provide, as a minimum, information about the following: reactivity control; reactor core cooling and primary system heat removal; reactor coolant system integrity; radioactivity control; and containment conditions.

The primary purpose of an available SPDS would be to display a full range of these important plant parameters in order to aid the control room personnel in determining the safety status of the plant during abnormal and emergency conditions and in assessing where abnormal conditions warrant corrective operator action to avoid a degraded core event. We assume that operators need all available parameter information for their decision-making in avoiding a degraded core event and that a properly functioning SPDS would result in a lower frequency of control room operator errors and a corresponding reduction in core-melt frequency.

Possible Solution

For the analysis of this issue, it is assumed that all plants have or will have installed an SPDS. It is conservatively assumed that, at 75% of the plants, the SPDS is not operational (i.e., not available for use) and that, at the remaining 25%, the SPDS is operational but, due to errors in design and/or construction, may provide misleading information to plant operators. For the resolution of this issue, we have assumed that improvements in design and hardware charges, as well as improved maintenance and test procedures, will be required to assure the availability of a properly functioning SPDS at all operating plants.

PRIORITY DETERMINATION

Assumptions

During the prioritization of a selected group of MPAs in October 1984, MPA F-09 was analyzed by PNL.[1039] The PNL analysis evaluated the risk reduction benefit obtained by the design, installation, and maintenance of an operating SPDS. The PNL cost analysis evaluated the NRC and licensee costs expected for the design, procurement, installation, and operation of the SPDS over the expected plant lifetime.

The PNL risk analysis for MPA F-09 is based on NUREG/CR-3246[1040] and the IREP risk assessment for Arkansas Nuclear One, Unit 1 (ANO-1).[366] NUREG/CR-3246[1040] deals with the risk reduction related to three improvements in the control room: (1) installation of a SPDS; (2) installation of a margin to saturation annunciator; and (3) increased control room staffing. Since the risk reduction associated with the availability of an operable SPDS is the concern of this issue, the analysis of NUREG/CR-3246[1040] was used and modified to separate out the effect on core-melt frequency due to having an operable SPDS. The effect on core-melt frequency due to the SPDS was then carried through the appropriate event sequences and minimal cut sets in the IREP risk assessment to determine the potential level of public risk afforded by an operable SPDS.

For the purpose of the analysis of this issue, we have conservatively assumed that 75% of all plants have an SPDS which is installed but not operationally available and 25% of the plants have an operational SPDS which provides misleading information. It is assumed that resolution of this issue would assure that all plants have a properly operating SPDS available and continuously in use.

Frequency Estimate

The level of risk presented by having SPDS installed but not available is the same as not having an SPDS. Therefore the PNL risk analysis for MPA F-09 is used to estimate the risk reduction afforded by resolution of this issue (i.e., making the installed SPDS continuously available and correcting any existing design or operational deficiencies) for the 75% population of the plants. For the remaining 25% of the plants, which are assumed to have an SPDS which might mislead the control room operators, we have assumed a two order of magnitude increase in the frequency of failure to notice relevant annunciators, failure to properly diagnose the event, errors of omission in following emergency procedures, errors of commission in establishing HPI cooling and recovery factors for operator errors and have repeated the PNL analysis using these modified probabilities for specific events in the cut set analysis.

The population of plants (75%) assumed to have an installed but unavailable SPDS was estimated to consist of 60 PWRs and 27 BWRs with remaining life times of 32 years and 30.8 years, respectively. The event tree (HPI-PUMP-CM), which depicts failure of HPI, was assumed to be affected by the addition of an SPDS. The event tree includes failure of adequate core cooling as the initiating event and individual probabilities for the failure to notice relevant annunciators, failure to properly diagnose the event, errors of omission in following emergency procedures, errors of commission in establishing HPI cooling, and recovery factors for various operator errors. The base case probability from NUREG/CR-3246[1040] for the HPI-PUMP-CM event is 2.18×10^{-3}.

In the SNL study of control room improvements (NUREG/CR-3246),[1040] the addition of an SPDS in the control room was assumed to reduce the probability of the operator failing to recognize the loss of margin-to-saturation annunciators from 1.3×10^{-2} to 10^{-4} (an improvement in the recovery factor) and provide a capability to detect omission of steps in the emergency procedure (an additional path on the event tree with a failure probability of 10^{-4}). The adjusted case probability of the HPI-PUMP-CM event was determined to be 4.4×10^{-4}.

In the MPA F-09 analysis, PNL calculated the change in core-melt frequency using the ANO-1 IREP analysis with the base case and adjusted case frequencies for the HPI-PUMP-CM event. The calculated change in core-melt frequency represented the addition of an SPDS for each dominant sequence of events in which the affected event (HPI-PUMP-CM) appears. For the purpose of determining the potential risk reduction for resolution of this issue for the 75% population (i.e, improving availability of existing SPDSs), this is the same as the MPA F-09 analysis with and without the SPDS as determined by PNL. The affected base case core-melt frequency (without SPDS) was calculated to be 1.04×10^{-6}/RY and the adjusted case affected core-melt frequency (with SPDS) was calculated to be 2.09×10^{-7}/RY. The core-melt frequency reduction (8.3×10^{-7}/RY) determined by PNL was assumed to be typical of all PWRs.[1039] When the change in core-melt frequency for PWRs was multiplied by the appropriate dose conversion factors, the number of affected PWRs (60) and their average remaining lifetime (32 years), a risk reduction of 3802 man-rem was estimated. The estimates of core-melt frequency and risk reduction for BWR plants were determined by proportioning the total core-melt frequency and total public risk from the ANO-1 IREP and Grand Gulf 1 RSSMAP risk assessments and multiplying the ratio to the PWR core-melt frequency and risk reduction estimates determined above. Core-melt frequency and total risk reduction estimates, due to the addition of an SPDS, of 6.1×10^{-7}/RY and 4,116 man-rem, respectively, were thus calculated for 27 affected BWRs for their average remaining lifetime (30.8 years). Thus, summing the BWR and PWR estimates, we calculated a total public risk reduction of 7,918 man-rem for resolution of this issue for the 75% population of plants assumed to have poor availability, based on PNL's MPA F-09 calculations.

We determined that the remaining 25% population of plants, which we assumed had an available SPDS capable of misleading the plant operators during abnormal operations, consists of 20 PWRs and 10 BWRs with a remaining life time of 32 years and 30.8 years, respectively. Due to the detrimental effect a faulty SPDS can have on a situation in the control room, we considered an increase in the probability of two orders of magnitude from the case where no SPDS was considered, for the following parameters: failure to notice relevant annunciators, misdiagnosis, and errors of omission in the respective steps of the emergency procedures. Repeating the PNL MPA F-09 analysis of using the higher operator error values, we calculate a PWR HPI-PUMP-CM probability of 1.75×10^{-2} and, using the ANO-1 minimal cut sets, a PWR core-melt frequency of 8.76×10^{-6}/RY. Using the above ratioing technique we estimate a BWR core-melt frequency of 6.6×10^{-6}/RY. Subtracting the base case (good SPDS continually available) estimated core-melt frequencies (2.09×10^{-7}/RY for PWRs and 1.55×10^{-7}/RY for BWRs) from the adjusted case values for the 25% population of plants with "faulty" SPDS, we estimate a core-melt frequency reduction of 8.55×10^{-6}/RY for PWRs and 6.44×10^{-6}/RY for BWRs.

Consequence Estimate

Multiplying the core-melt frequency by the appropriate dose conversion factors, number of affected plants (20 PWRs and 10 BWRs) and their respective average remaining lifetimes (32 yrs for PWRs and 30.8 yrs for BWRs) we estimate a potential public risk reduction of 13,376 man-rem for the PWRs and 16,301 man-rem for the BWRs of the remaining 25% population of plants. Summing the PWR and BWR estimated risk reductions for the 25% population of plants assumed to have a faulty SPDS we estimate a total risk reduction for this fraction of the total population of plants of (13,376 + 16,031) man-rem or 29,407 man-rem.

Since resolution of the issue is assumed to both greatly improve availability of the SPDS and correct the deficiencies in those SPDS which may be "faulty," the total risk reduction estimated for the issue is (7,918 + 29,407) man-rem or 37,325 man-rem.

Cost Estimate

Industry Cost: For the MPA F-09 cost analysis, PNL consulted industry vendors who supplied SPDS systems. PNL estimated an industry SPDS implementation cost of $3M/plant equally divided between vendor procurement costs and licensee design and installation costs. For the purpose of this analysis, we assumed that modifications to an existing SPDS to correct either severe availability problems or design deficiencies cannot be accomplished for less than 10% of the original design, procurement, and installation cost. We, therefore, estimated a total industry implementation cost for this issue of $35.1M.

In the MPA F-09 analysis, PNL estimated 2 man-weeks/yr/plant of industry effort required to operate, inspect, and maintain the SPDS. For this analysis, we estimate that one additional man-week of industry maintenance and surveillance effort will be required per year to maintain and demonstrate adequate SPDS availability. We calculated a total present worth industry cost of $8.4M for operation and maintenance of an improved SPDS at all affected plants. We, therefore, estimated a total industry cost of $43.5M.

NRC Cost: We estimate that 12 man-weeks/plant of NRC effort would be needed to review the SAR on a modified SPDS, prepare an SER supplement, inspect the SPDS after its modification, and review and issue revised technical specifications for the operation and surveillance of the SPDS. The staff estimated the cost to be $270,000/plant or $3.2M total cost for the safety issue resolution (SIR) implementation support. In addition we estimate that one man-week/plant/yr of NRC effort would be required to review and monitor the licensee's improved (expanded) maintenance and surveillance program. When costed out a $2,270/man-week, an NRC present worth cost of $8.4M for SIR operation and maintenance review is estimated. We, therefore, estimate a total NRC cost of $11.6M.

Value/Impact Assessment

The value/impact score derived from the above estimates is as follows:

$$S = \frac{37,325 \text{ man-rem}}{\$(43.5 + 11.6)\text{M}}$$

$$= 677 \text{ man-rem/\$M}$$

Other Considerations

Control room instrumentation systems have been designed in compliance with GDC 13 and 19 of Appendix A to 10 CFR 50 and, as such, are required to provide the operators with the information necessary for safe reactor operation under normal, transient, and accident conditions. The SPDS is used in addition to the control room instrumentation system to aid and augment the control room instrumentation system. Supplement 1[376] to NUREG-0737 required that licensees develop procedures which describe the timely and correct safety status assessment when the SPDS is and is not available. It also required that operators be trained to respond to accident conditions both with and without the SPDS available. The SPDS is therefore viewed as enhancing the operator's perception and understanding of plant status under normal and abnormal conditions, but the SPDS is not essential to proper and timely diagnosis and effective recovery from abnormal events. The normal plant instrumentation system is a redundant safety grade system. The SPDS addition provides a diverse and improved diagnostic system but in itself is redundant to the plant instrumentation system, which by the nature of its design requirements, is redundant within itself.

Since all modifications, maintenance, and surveillance will be performed in the control room complex, there is no potential ORE expected for this issue. The SPDS is a redundant (but enhanced) back-up system for the redundant, safety-grade control room plant instrumentation system. Intuitively, one would, therefore, not suspect that the risk sensitivity to SPDS availability (7,918 man-rem) would be so great as to warrant improvements in SPDS availability regardless of cost. In addition, the risk analysis performed for this issue was performed conservatively assuming that poor availability meant 100% unavailability of the SPDS for the population (75%) of plants assumed to suffer from less than desired availability.

If the availability concern were considered separately, i.e., the total population of plants (100%) was assumed to have an SPDS which is unavailable the maximum public risk contribution (calculated conservatively) would be about 10,400 man- rem. In this instance, a medium priority would be warranted unless the total cost per plant to increase availability significance were less than $30,000, which seems highly unlikely.

If the smaller population of plants (30) assumed to have "faulty" SPDS (i.e., one which may mislead control room operators during their response to a transient or LOCA) is considered separately, a much larger potential public risk contribution (29,407 man-rem) is estimated. This averages out to slightly less than 1,000 man-rem/reactor for this smaller population. A medium priority is appropriate for this concern unless the cost to modify the SPDS equipment to correct the design faults were less than approximately $300,000/plant (10% of the SPDS original cost). We feel that reanalysis of design and equipment replacement or modification for less than 10% of the original procurement cost are unlikely.

Conversely, recognizing that the foregoing treatment of the case of the operator being misled is conservative, if one were to assume that there is no chance of the SPDS misleading the operator (i.e., no public risk impact), the priority assignment would be based solely on the risk potential associated with the availability concern and the issue would still warrant a medium priority assignment. Therefore, considering both the overall risk and cost calculations and the separate effects for the two separate concerns identified by the Davis-Besse event (i.e., availability and design adequacy) and the limited surveys of SPDS status at operating plants, the potential risk reduction and the value impact ratio would indicate a medium priority assigment.

CONCLUSION

Generic Letter No. 82-33[376] transmitted Supplement 1 to NUREG-0737 to clarify the TMI action items related to emergency response capability, including Item I.D.2, "Safety Parameter Display System." Supplement 1 extracted the fundamental requirements for emergency response capability from the wide range of regulatory documents issued on the subject. It was written at the conceptual level to allow for a high degree of flexibility in scheduling and design. In recognition of the interrelationships among the action items addressed in Supplement 1, the staff made allowance for each licensee to negotiate a reasonable schedule for implementing its emergency response capability. However, the staff identified the SPDS as an improvement to the control room that should not be delayed by progress on other initiatives.

The staff evaluated licensee/applicant implementation of the SPDS requirements at 57 units and found that a large percentage of designs did not satisfy requirements identified in Supplement 1 to NUREG-0737. Generic Letter 89-06[1205] (enclosing NUREG-1342[1206]) was issued to inform licensees of the staff's findings to aid in implementing SPDS requirements. NUREG-1342[1206] describes methods used by some licensees/applicants to implement SPDS requirements in a manner found acceptable by the staff. NUREG-1342 also documents design features that the staff found unacceptable and gives the staff's reason for finding them unacceptable. The information in NUREG-1342 does not constitute new requirements; Supplement 1 to NUREG-0737 contains NRC's requirements for SPDS. With the issuance of Generic Letter No. 89-06,[1205] this issue was RESOLVED and requirements were established.[1207]

ITEM 125.I.4: PLANT-SPECIFIC SIMULATOR

DESCRIPTION

Historical Background

This issue was identified as Item 10c in the EDO memorandum [895] and was based on Findings 10 and 17 and Sections 6.1.1 and 6.1.2 of NUREG-1154.[886] Following the Davis-Besse reactor trip, the operator manually initiated actuation of the Steam and Feedwater Rupture Control System (SFRCS) in anticipation of the automatic initiation of the SFRCS; however, the operator pushed the wrong buttons. This was the first time he had manually actuated the SFRCS and had not received specialized classroom or simulator training on correctly initiating the SFRCS. The buttons pushed by the operator activated the SFRCS on low pressure for each steam generator instead of low level. By manually actuating the SFRCS on low pressure, the SFRCS was signalled that both steam generators had experienced a steamline break or leak and the system responded, as designed, to isolate both steam generators. Thus, the operator's anticipatory action defeated the safety function of the AFW system. The error was corrected within approximately one minute by resetting the SFRCS and, therefore, had no significant bearing on the outcome of the event. However, the lack of plant-specific simulator training was noted by the investigating team.

This event, however, was not the first event that indicated the need for plant-specific simulator training. The TMI-2 event on March 28, 1979, clearly focused industry and NRC attention on the need for better human engineering in control room design and for plant-specific simulator training. TMI Action Plan Task I.A[48] contained a series of requirements related to simulator uses and developments addressing short-term and long-term actions centered on simulator training. Some of the Task I.A items[48] were subsequently integrated into the Human Factors Program Plan (HFPP)[651] which was developed in response to NUREG-0885[210] and Section 306 of the Nuclear Waste Policy Act of 1982 (PL 97-425). In this regard, PL 97-425 required NRC to establish simulator training requirements for plant-licensed operators and operator requalification examinations. Item I.A.4.1, "Initial Simulator Improvement," has been completed; the "Long-Term Training Simulator Upgrade" [Item I.A.4.2(4)] will be completed upon publication of 10 CFR 55 and related NRC guidance on the evaluation of simulation facilities.

Safety Significance

A plant-specific simulator would improve operator actions and timing in response to plant transients and accidents. Thus, plant damage and possible core-melt accidents could be significantly reduced. This issue affects all licensed nuclear power plants.

Possible Solution

The use of plant-specific simulators is being addressed in the proposed rulemaking[957] amendments to 10 CFR 55 [TMI Action Plan Item I.A.4.2(4)]. This action will codify requirements that include the use of nuclear power plant simulators in initial and requalification examinations. In brief, the proposed rulemaking includes three choices for plants that are not the reference plant for a simulator: (1) acquire a plant-referenced simulator that meets the intent of Regulatory Guide 1.149;[439] (2) use a simulator that conforms to Regulatory Guide 1.149[439] and has been demonstrated to be suitable; or (3) substitute any device or combination of devices that meets the requirements of 10 CFR 55.45(b) and would be approved by the NRC.

CONCLUSION

Based on the above, the resolution of the need and use of plant-specific simulators is being addressed as part of the proposed rulemaking amending 10 CFR 55 under Item I.A.4.2(4). Thus, Issue 125.I.4 was DROPPED as a separate issue.

ITEM 125.I.5: SAFETY SYSTEMS TESTED IN ALL CONDITIONS REQUIRED BY DBA

DESCRIPTION

Historical Background

The issue is based on Finding 15 of the IIT report[886] which states: "Thorough integrated system testing under various system configurations and plant conditions as near as practical to those for which the system is required to function during an accident is essential for timely detection and correction of common mode design deficiencies."

Safety Significance

Section 7 of the IIT report attributed the key safety significance of the Davis-Besse event to the fact that multiple equipment failures occurred, initiating a transient beyond the design basis of the plant. According to the IIT report, each of the following conditions contain a mix of operating errors, maintenance errors, and design errors that, without corrective operator actions, would have defeated operation of the safety-related AFW system. These are as follows:

(1) Operator Error in SFRCS Actuation on Low Pressure

Following the loss of main feedwater during the event, the operator, in anticipation of Steam and Feedwater Rupture Control System (SFRCS) actuation on low steam generator water level, inadvertently pushed the wrong two buttons which activated the SFRCS on low steam generator pressure instead of low steam generator water level. By manually actuating the SFRCS on low pressure, the SFRCS was signaled that both steam generators had experienced a steamline break or leak. Thus, the operator's anticipatory action (human error) defeated the safety function of the AFW system. The shift supervisor quickly determined that the AFW system valves were improperly aligned and reset the SFRCS (tripped it on low level) and corrected the operator's error about a minute after it occurred.

(2) Failure of the AFW System Containment Isolation Valves to Reopen after Their Inadvertent Closure

After the shift supervisor had reset the SFRCS, both AFW containment isolation valves could not be reopened from the control room either automatically or by manually operating the SFRCS reset and block following the inadvertent closure. This caused the complete loss of the AFW safety function by blocking flow of the AFW to both steam generators. The probable root cause of the AFW containment isolation valves inability to reopen was attributed to improperly adjusted torque switch settings on the valve actuator. Thus, power to the actuator motor was cut off before the valves could open against the high differential pressure across the valves. The safety function for the AFW isolation valves had been incorrectly specified as only to close, not to open or reopen. Thus, the AFW and SFRCS design reviews revealed that neither system met the design single failure criterion with respect to opening an AFW containment isolation valve to feed an intact steam generator. The containment isolation valves were opened by dispatching equipment operators to the rooms containing the valves where they reopened the valves in about 3.5 minutes.

(3) Overspeed Tripping of the AFW Pumps

The operator, after returning to the AFW station, expected the AFW to be actuated and providing the needed feedwater to the steam generators. Instead, he saw the No. 1 AFW pump, followed by the No. 2 AFW pump, trip on overspeed. Had both systems (the AFWS and the SFRCS) operated properly, the operators mistake in pushing the wrong buttons would have had no significant consequences. A review of the AFW design indicated that the AFW steam crossover lines (i.e. those associated with the opposite steam generator for each AFW turbine and steam admission valves) have long horizontal runs where saturated hot water could accumulate. Thus, the fluid entering the AFW turbines initially was a mixture of water and steam, but soon was entirely steam. The turbine governors could not respond quickly enough to the changing energy content of the fluid being provided and the turbines tripped on overspeed. However, the turbine overspeed trips were cleared by opening the trip throttle valves located in the AFW pump rooms.

The Davis-Besse event demonstrated the susceptibility of redundant equipment to various common mode failures and the importance of "defense-in-depth" and operator training to ensure safety. The value of redundancy, diversity, and prompt and effective operator action in accomplishing key safety functions was particularly evident from the Davis-Besse event.

Possible Solutions

In accordance with Finding 15, an essential solution for timely detection and correction of common mode design deficiences would be to conduct thorough integrated system testing under various system configurations and plant conditions (as near as practical) for which the systems are required (designed) to function during an accident.

To develop a Finding 15 test program, tests would have to be devised to simulate various plant conditions, equipment alignments, and plant responses (possible functional and spatial coupling mechanisms) to postulated abnormal and accident situations. To facilitate identification of unforeseen common mode design deficiencies (CMDD-triggers) in equipment or systems, a judicious selection of induced equipment malfunctions and/or operator errors may need to be modeled into the tests. Because it is virtually impossible to model or test for all possible off-normal conditions, the problem of devising such tests are similar to the problems encountered by the staff during development of the Design Basis Events (DBEs) used to license plants. In establishing the DBEs, the staff recognized that it was impractical, if not impossible, to anticipate (postulate) all possible transients, abnormal operations, accident conditions, equipment malfunctions, and operator errors that may occur during the life of a plant. To overcome these limitations and to provide adequate assurance that the plants could operate safely, the staff included DBEs in the SRP[11] in an attempt to bound the unforeseen events that might occur.

For the purposes of estimating the potential scope of this issue, and due to the similarities between the objectives stated in Finding 15 and the licensing DBEs, it was assumed that a thorough integrated system test program might, as near as practical, attempt to simulate the postulated licensing DBEs described in SRP[11] Section 15. Because of the complexities involved in attempting to simulate all the DBE conditions, the possibilities of inducing some fuel failures under the more severe DBEs, and the physical limitations of actually conducting tests to model many of the DBEs, it does not appear practical or realistic to conduct a test program under all DBE conditions.

For purposes of this analysis, it was assumed that the closest approach to the Finding 15 recommendation (to conduct a thorough integrated systems/plant test program) may be a test program similar to the Rancho Seco restart test program. However, because plant-specific test programs may vary significantly, the potential range in costs of each plant-specific test program, as discussed herein, reflect a wide range of potential costs which may be dominated by possible extended refueling outages that may result from implementing the test programs.

The Rancho Seco test program includes component testing, systems integrated functional testing, and plant integrated functional testing. These tests include logic tests of systems interlocks, trips, permissives, and verifications of the annunciators. Normal operations testing would include cold and hot shutdown conditions, with some testing performed during the power ascension phase. During the normal operations testing, verification of systems functions will be conducted. Many of these tests are already performed during In-Service Testing (IST) or during normal refueling outages, but improved methods and procedures may be needed and may affect on-line power production. The integrated Rancho Seco systems/plant testing phase includes, where practical, emergency/off-normal operations such as the loss of the Integrated Control System (ICS), Non Nuclear Instrumentation (NNI), offsite power, and ECCS testing.

Based on the Rancho Seco test flow diagram, many of the latter tests, such as cold functional Emergency Feedwater Integrated Control (EFIC), Safety Feature Actuation Systems (SFAS), diesels, and condenser vacuum tests, can be performed in parallel over approximately 3.5 months. However, the loss of offsite power, plant heatup, hot shutdown, and power ascension testing would be conducted in series over an additional 3.5 months. In summary, it is estimated that the

Rancho Seco systems/plant testing phase will require approximately 7 months to complete and includes the following major integrated test matrix:

(1) Loss of offsite power
(2) Integrated SFAS
(3) Loss of instrument air
(4) EFIC functional
(5) Loss of ICS/NNI power
(6) Condenser vacuum
(7) Integrated leak test
(8) Flow balance
(9) Cold systems functional
(10) Hot systems functional
(11) Power systems functional
(12) Reactor trip
(13) ICS tuning

It is noted, however, that the integrated systems/plant test matrix does not include all the DBEs. Nevertheless, the Rancho Seco test program should provide insight into the potential magnitude and scope of an integrated systems/plant testing program, under various systems configurations and plant conditions, that may approach the Finding 15 recommendation. However, to meet the Finding 15 objective of detecting unforeseen CMDDs, it may be necessary to devise and include by judicious selections, off-normal equipment malfunctions and operator errors to provide the coupling mechanism(s) that force detection of the unforeseen CMDDs.

Because of the infinite combinations of possible equipment or system malfunctions and operator errors, the likelihood of success in detecting unforeseen CMDDs by a <u>designed</u> test program, using limited and <u>designed</u> combinations and <u>designed</u> procedures, will likely be plant-specific. The chance of success may be severely limited by the imagination used in devising the tests and in selecting appropriate coupling mechanisms that will force detection of the unforeseen CMDDs.

The potential complexities in developing a thorough integrated systems/plant test program, especially one designed to detect unforeseen CMDDs, are enormous and should not be considered a simple engineering task nor a series of simple tests. Nevertheless, for the purpose of this analysis it will be assumed that the integrated systems/plant testing phase may be reduced by a factor of ten to 0.7 months (3 weeks) beyond the normal refueling outage. Thus, outage extensions that may range from 3 weeks to 7 months should bound all or most of any plant-specific variabilities in outage extension costs that may be attributed to the test programs.

PRIORITY DETERMINATION

The objective of the Finding 15 integrated systems/plant test program is to detect and correct unforeseen (unknown) CMDDs that may surface as a result of off-normal or accident conditions during plant operations. Since no specific event or safety system is identified in Finding 15, the problem involves virtually every safety system in a plant. Because all plants exhibit various degrees of complexities in their safety systems and various susceptibilities to common mode failures, any attempt to identify plant/system hazards for all possible common mode failures (especially unknown common mode failures) either singly or in combinations is impossible. Therefore, to a large extent, plant-specific hazards from all common mode failures may vary considerably from plant to plant. These conditions also apply to the unforeseen CMDDs (a subset of common mode failures) which are considered in this analysis.

Currently, the methods for systematically evaluating equipment or system failures involve the use of operational data. This data provides equipment and system unavailabilities to estimate the probabilities of dominant accident sequences that may lead to core damage (considered herein as a core-melt condition). The operational data on equipment and system unavailabilities generally include common mode or common cause events that are not specifically identified in the systemic event tree of the accident sequences. A fault tree model of the equipment or system would contain more specific information on common mode or common cause initiators that affect the specific equipment or system unavailabilities.

The items that will be addressed in this analysis are: (1) the likelihood of unforeseen CMDDs that have not yet occurred; (2) the chance of success of detecting and correcting unforeseen CMDDs; (3) the likelihood of core-melt from unforeseen CMDDs; (4) the estimated risk reduction potential associated with detecting and correcting the unforeseen CMMDs; and (5) the estimated cost range of implementing possible thorough integrated systems/plant test programs discussed earlier.

Frequency Estimate of Unforeseen CMDDs: To estimate the frequency of unforeseen common mode failures, information was obtained on the frequency of previous unforeseen common mode failures that have actually surfaced in operating plants. The information used in this analysis is based on results of research conducted by EPRI.[745] The data gathered in the EPRI report was limited to a select group of components covering approximately 400 to 600 RY of experience; 2654 events were evaluated in the EPRI report and each event involved at least one component in an actual or potential state of being failed or functionally unavailable. Of the 2654 events, 2232 were classified as independent events and 422 were classified as dependent events. Of the dependent events, 113 were classified as common cause events and 68 were classified as actual common cause events because they involved two or more actual failed or functionally unavailable states.

The method used in the EPRI report to quantify equipment common cause failure values is the Basic Parameter Method (BPM). The overall methods included in the EPRI report involved essentially an extension of the Beta Factor Method and the Multiple Greek Letter Method. These methods provided means for estimating the conditional probabilities from common cause events involving two, three, or more units, given that a specific component failure occurs.

The generic beta basic parameter values calculated by EPRI reflect the compilation of all the reviewed data on common mode failures for the components and systems listed below. In accordance with NUREG-1150,[1081] these EPRI values reflect a 95% upper bound of a log normal distribution with an error factor of three. The mean values (taken from NUREG-1150) are listed and are used in this analysis to estimate the potential generic contribution to core-melt frequency from common cause failures. The upper bound beta basic parameter values were used in the NUREG-1150[1081] sensitivity study to bound the potential effects of common cause failures (CCFs) on severe core damage.

The EPRI report includes the results of extensive data reductions, root-cause determinations, and evaluations of 2654 events that included independent and dependent events over 400 to 600 RY of operation. Because plant-specific data are scarce even for single failure probabilities (and even more scarce for dependent failures), use of the EPRI industry-wide data provides a more comprehensive generic data base than the Davis-Bessie event that involved multiple component/systems failures.

Generic Beta Values

Component	Upper Bound Values	Mean Values
Reactor Trip Breakers	0.19	0.079
Diesel Generators	0.05	0.021
MO Valves	0.08	0.033
SRVs		
PWR	0.07	0.029
BWR	0.22	0.092
Batteries	0.1	0.04
Pumps		
High Head	0.17	0.071
RHR	0.11	0.046
Cont. Spray	0.05	0.021
AFW	0.03	0.013
Serv. Water	0.03	0.013
All[a]	0.1	0.042

a = Average of all beta BPM values

In addition to the above beta BPM values, the EPRI report grouped the failure events into two classes. The Class I failures included all the generic common cause events. Both classes were classified as having eight generally related causes (triggers). Although the Class I events occurred 10 times less frequently than the Class II events, the relative frequencies of the cause (trigger) groups suggested that the causes of dependent events in general, and common cause events in particular, are not unique. The fundamental difference between the dependent and independent events is that the former has a coupling mechanism to transmit the effect of the trigger to two or more components, and the latter exhibits no such coupling mechanism(s). Examples of coupling mechanisms are functional dependence, spatial proximity, and human interactions. The distribution of the common cause triggers as a fraction of the overall common causes are listed below:

Common Cause (Trigger) Fractional Distributions

(1) CMDDs* 0.25
(2) Erroneous Procedures...0.10
(3) Other Plant/Staff Errors (including maintenance).......0.16
(4) Testing (not including instrumentation calibrations)...0.01

(5) Internal Causes..0.15
(6) Environmental Stress.....................................0.08
(7) Unknown..0.19
(8) Multiple Causes..0.06

* CMDDs consist of design, manufacturing, construction, and installation errors.

Based on the above common cause fractional distribution reported in the EPRI study, CMDDs on an average account for approximately 25% of the EPRI beta BPM values. The first four common cause triggers listed above are more basically grouped in the EPRI report as human-related causes and account for approximately 50% of the overall common cause failure contributions.

It was assumed that the unforeseen CMDDs from plant modifications and equipment replacements will continue at the approximate rate evaluated from the EPRI data base of dependent failures that occurred over the 400 to 600 RY of operation. Since the component/systems unavailabilities used in plant PRA analyses contain various components/systems with various beta (common cause) values, we will assume the average 25% contribution attributed by EPRI to CMDDs is generally applicable to all component/system beta BPM values.

<u>Core-Melt Frequency Contribution from Unforeseen CMDDs</u>: NUREG-1150[1081] provided a sensitivity study of the effects of common cause failures on severe core damage frequencies using four plant PRAs: Surry, Peach Bottom, Sequoyah, and Grand Gulf. The results in brief showed that dependent failures are basically plant-specific and subject to large variations from plant to plant, and that dependent failures are a major contribution to severe core damage frequency and, in some cases, risk. The NUREG-1150[1081] sensitivity study adjusted each of the PRA dominant accident sequences of the 4 plants to account for plant-specific, generic, and upper bound common cause beta values. The analyses also included base-case core-melt frequencies with beta set equal to zero to identify the overall contribution and sensitivity of severe core damage to the range of common cause beta values.

The pertinent NUREG-1150[1081] upper bound results and the generic mean value estimates are tabulated in Table 3.125-1. The mean values of the generic beta values are based on a log normal distribution with an error factor of three. Based on the results in Table 3.125-1, the average core-melt frequency for the four plants, considering the mean value common cause beta BPM values, is 9.2×10^{-5}/RY. This average core-melt frequency is assumed representative of the generic core-melt frequency for all operating plants. Use of average values smooth the outlier high and low plant-specific vulnerabilities to common cause failures and is more appropriate for a generic plant analysis (if indeed there is a generic plant).

As evident from the Table 3.125-1 tabulation, the contributions to plant-specific core-melt frequencies from all common cause contributors vary by approximately an order of magnitude, indicating the large plant-specific effect on core-melt frequency from common cause type failures. The contribution to the average core-melt frequency from common cause failures is $(0.427)(9.2 \times 10^{-5}/\text{RY}) = 3.9 \times 10^{-5}$/RY. Using 25% of the common cause contribution to account for only the unforeseen CMDDs yields a core-melt frequency contribution of 9.8×10^{-6}/RY from unforeseen CMDDs. Put another way, 42.7% of the generic plant core-melt frequency is attributed to estimated common cause failures (a significant contribution), where 10.7% of the core-melt frequency is attributed to estimated unforeseen CMDDs.

Frequency of Detecting Unforeseen CMDDs: It is expected that in the majority of tests performed to simulate normal or off-normal plant operations, initiation and operation of safety systems, where systems are manually started, stopped, restarted, realigned, throttled, or otherwise operated in ways not easily anticipated by the designer, the system will usually work as expected.

Table 3.125-1

Core-Melt Frequency Contributions

Plant	Beta=0 (A)	Beta BPM Contributions Upper Bound Values (B)	Mean Values (C)	(A+C)	(C)/(A+C)
Surry	1.5×10^{-5}	2.1×10^{-5}	8.8×10^{-6}	2.4×10^{-5}	0.367
Peach Bottom	3.4×10^{-6}	7.6×10^{-6}	3.1×10^{-6}	6.5×10^{-6}	0.472
Sequoyah	7.1×10^{-5}	5.7×10^{-4}	2.4×10^{-4}	3.1×10^{-4}	0.774
Grand Gulf	2.3×10^{-5}	6.0×10^{-6}	2.5×10^{-6}	2.6×10^{-5}	0.096
Average	-	-	-	9.2×10^{-5}	0.427

To estimate the likelihood of detecting an unforeseen CMDD, the experience of the Davis-Besse AFW system was considered. At the time of the June 9, 1985 event, this plant had accumulated about 6.8 calendar-years of operation. Loss of main feedwater (LMFW) events occur roughly three times per reactor-year, so the June 9, 1985 LMFW event was preceded by roughly 15 AFW system actuations (assuming a 25% average outage time). Note that these actuations are only system initiations. Three loss of feedwater events per year corresponds to all feedwater losses, most of which are partially or easily recoverable. At the same time, the problems in the Davis-Besse AFW system and its associated controls and valving were there all along, but were not discovered (detected) until about 15 actuations had occurred. This limited plant-specific (Davis-Besse) information would infer that the probability of detecting an unforeseen CMDD, with the coupling mechanism(s) attributed to off-normal or unusual operation, is approximately 1/15 or 0.067 per event.

Alternately, if we consider the information contained in the EPRI report[74] involving 255 AFW failure events, we note that only three of the events exhibited the necessary coupling mechanisms to detect common cause failures. Combining the Davis-Besse event with the 255 EPRI events indicates that the chance of detecting a common cause failure in PWR AFW systems per event is small (on the order of 0.01/event).

Additional evidence of the CMDD detection chance is suggested by other EPRI data. As discussed earlier, the fundamental difference between independent and dependent event failures is that the dependent, and common cause event failures in particular, must include a coupling mechanism(s) to transmit the effect of the trigger (cause) to two or more components. Therefore, the 68 events in the EPRI data base of 2654 events that involved two or more actual failed or functionally unavailable states must have included some form of coupling mechanism(s). This would also suggest a detection (coupling) chance of approximately 0.03/event for a broader range of equipment and causes. Averaging the above operating experiences, we estimate the chance of detecting a significant number of CMDDs during each plant-specific test program at 0.035.

Because the above estimates are based on data of events involving failures, they should not be confused with a per demand rate of components/systems. If a demand rate of components/system were considered, it would need to be factored into the above estimate to obtain the chance of common cause failures per test demand. Therefore, use of the above ratios to estimate the chance of detecting unforeseen CMDDs during a one-time series of tests may be biased toward a conservative estimate, since it is conditional on the given occurrence of some random or induced human/component/system failure during the test. Normally, we would not expect either independent or dependent failures to occur during the course of a transient or test. However, this estimate should be sufficient for purposes of this generic issue analysis.

Reduction in Core-Melt Frequency: Based on the previous calculations, the potential core-melt frequency contribution from unforeseen CMDDs, prior to the test program, was estimated to be 9.8×10^{-6}/RY. After the tests, the core-melt frequency is weighted by the probability of the CMDDs not detected (1 - 0.035) = 0.965. Therefore, the reduction in core-melt frequency from detecting and correcting the unforeseen CMDDs is:

$$\Delta CMF = (1 - 0.965)(9.8 \times 10^{-6})/RY = 3.4 \times 10^{-7}/RY$$

Consequence Estimate

The conditional release doses used in this analysis are based on the fission product inventory of a 1120 MWe PWR, meteorology typical of a midwest site, a surrounding uniform population density of 340 persons per square mile within a 50-mile radius of the plant, an exclusion radius of one-half mile from the plant, no evacuation, and no ingestion pathways. Therefore, the estimated change in risk is representative of the hypothetical generic PWR plant and not representative of any specific plant. For BWR plants, the results are not expected to be greatly different.

Based on NUREG/CR-2300,[187] the probability of a large release (5.1×10^6 man-rem/CM) is 0.2 and the probability of a basemat melt-through type release (1.5×10^5 man-rem/CM) is 0.8. Over a plant lifetime of 30 years, the resulting estimated risk reduction associated with this issuse is (3.4×10^{-7}/RY) x (1.2×10^6 man-rem)(30 years) = 12 man-rem/reactor.

Cost Estimate

A thorough integrated systems/plant test program that models various systems/plant responses to off-normal and DBE accident events would be a major undertaking and highly plant-specific for all operating plants. The dominant costs are likely to be replacement power costs that may result from a test-extended outage. Design, engineering, plant hazard analysis, labor, and modification costs to ready the plant for such a test program would be significant. These costs are also highly plant-specific, but are not estimated. However, prior to implementation of the test program, a long lead time can be expected to be required for the licensee to develop, and for the NRC to review and approve, the test programs. A less rigorous test program may be possible and less costly if the test program can be accommodated largely within the normal refueling outage (7 weeks) with an estimated additional 3 week (0.7 month) outage extension.

The long lead time for a thorough test program, and the assumed necessity to phase-in all the plant (approximately 100 reactors) test programs over a specified time, to reduce the potential impact of lost electrical generation production from multiplant outages, are further considerations that would need to be considered in a more complete value/impact assessment of this issue because simultaneous (multiplant) outages tend to increase the costs of replacement power.

Replacement Power Costs: Based on the discussion provided before, a test program similar to the Rancho Seco restart test program may be needed to approach the Finding 15 recommendation that initiated this issue. We assume that the test programs will be a one-time series of tests for each plant and that the test programs may extend a plant refueling outage by 3 weeks (0.7 month) to 7 months, depending on the plant-specific test program and other tests scheduled to be performed during each plant's refueling outage. Using an average replacement power cost of $500,000 per day, the replacement power costs are estimated to be $11M to $110M per plant.

Plant Costs During Test-Extended Outage: It is difficult to provide detailed cost estimates of plant costs incurred during the test-extended outage period. These costs would involve engineering, management, labor, maintenance, and possibly some repair or modification costs. To estimate the plant costs during the test-extended outage period alone, it was assumed that the plant costs can be approximated by plant costs typically experienced from a forced outage. Based on NUREG/CR-3673,[1082] this cost is estimated at $1000/hour. For a test-extended outage of 3 weeks to 7 months, the plant costs are estimated at $0.5M to $5M per plant.

Combined Costs: The combined cost of replacement power and plant costs during a test-extended outage may range from $11.5M to $115M per plant. These combined costs do not include the significant but unquantified pre-implementation costs of the test program. However, this incomplete cost estimate provides insight into the large expense that may be involved in conducting a thorough integrated systems/plant test program for each operating plant. In addition, the NRC costs to review, approve, and follow the test programs in all operating plants would likely involve a large expenditure of NRC resources. For the optimistic outage extension of 3 weeks, the combined industry and NRC pre-implementation costs may approach the $11.5M cost of a short extended outage.

Value/Impact Assessment

(a) Long Extended Outage: Based on the risk reduction estimated to result from probable test identification and correction of unforeseen CMDDs (which is the focused goal of Finding 15) and the estimated range of the per-plant extended outage costs from the test programs, the range of the value/impact scores for this issue resolution is:

$$S < \frac{12 \text{ man-rem}}{\$115M}$$

$$< 0.1 \text{ man-rem}/\$M$$

(b) Short Extended Outage: If we assume that the integrated systems/plant DBE testing phase can be conducted in 10% of the time estimated by Rancho Seco for their integrated systems/plant testing, then the value/impact score is given by:

$$S < \frac{12 \text{ man-rem}}{\$11.5M}$$

$$< 1 \text{ man-rem}/\$M$$

However, the latter priority score may be overly optimistic because pre-implementation costs will take on more significance and may approach the $11.5M estimated for only the replacement power costs and plant costs.

Other Considerations

Due to the involved complexities and the long lead time before these test programs could be implemented, the test programs would not likely commence until the mid-1990s. Even if the programs for the 100 operating plants were phased over the following five-year time period (20 plants/year), the test programs would not be completed until the year 2000. During these time periods, a significant amount of operational experience would significantly expand the data base and corrections for many of the unforeseen CMDDs through other ongoing industry and NRC programs, e.g., improved LER requirements, Bulletins, Information Notices, NRC Generic Issues Program, the Safety Systems Functional Inspections (SSFI) Program, and the Individual Plant Examinations (IPE) Program, would be made. Therefore, the goal of Finding 15 to detect and correct unforeseen CMDDs may, to a significant degree, be achieved before the test programs can be initiated and completed. CMDDs that may result from plant modifications or equipment replacements that follow the test programs would also not be eliminated by the one-time test programs.

CONCLUSION

The stated goal of the proposed integrated systems/plant test programs of Finding 15 is to detect and correct unforeseen CMDDs. The Finding 15 recommendation to use integral plant/system testing, as near as practical to DBA conditions, to detect CMDDs seems too limited in its goal, considering the potentially large expenditure of time and resources that may be needed to develop the program. As evident by this analysis, the current state-of-the-art on CCFs is lacking sufficient information (data) and knowledge concerning coupling mechanisms that trigger CCFs. Without sufficient information (data) on the individual plants and a better understanding of the CCF coupling mechanisms, the successful result of the Finding 15 recommendation appears unlikely. The estimated success probability of the tests to detect all unforeseen CMDDs results in a potential reduction in core-melt frequency of 3.4×10^{-7}/RY. This reduction in core-melt frequency borders between a drop and low on the priority ranking matrix.

The risk reduction, not considering a time-averaged dilution before the tests would yield any benefits (risk and core-melt frequency reductions) as discussed above, is estimated at 12 man-rem/plant. This reduction borders between a drop and low on the priority matrix.

The above risk reduction, when divided by the large costs that may be involved in such a program, yields an estimated priority score in the range of less than 1 to 0.1 man-rem/$M. This value/impact range is approximately three to four orders of magnitude less cost-effective than the 1000 man-rem/$M that is generally considered to be a cost-effective resolution. However, due to the low risk reduction, the priority ranking is not affected by the estimated range of the priority scores for this issue.

The above results are based on mean generic beta values applied to four plant PRAs and the resultant average core-melt frequency of the four plants. This approach smooths out high and low plant-specific vulnerabilities to common cause type failures and is more representative of a hypothetical generic plant. Therefore, the results of this hypothetical generic plant analysis should not be construed to be representative of any specific plant, since plant-specific vulnerabilities to common cause type failures vary significantly from plant to plant.

It must also be recognized that the analysis of this issue is directed toward using thorough integrated systems/plant testing of DBE conditions (as near as practical) to detect and correct unforeseen CMDDs. In this regard, Finding 15 explicitly stated that thorough integrated systems/plant tests under these conditions is <u>essential</u> for the detection and correction of unforeseen CMDDs. This analysis <u>does not</u> support Finding 15 as an <u>essential</u> and <u>practical</u> solution for detecting and correcting unforeseen CMDDs. This is true even considering that the analysis done in this prioritization evaluates a wide range of time (3 weeks to 7 months) and cost ($11.5M to $115M) that would be incurred by a utility in doing integral testing. These estimates do not include considerable engineering, procedure development, and training costs that would also be incurred in preparing to run such tests. In addition, it has been proposed that such tests may be valuable in uncovering other CCFs from the triggers shown before. While it is theoretically possible to use integral testing for this purpose, the test program required would have to be more extensive and be done at periodic intervals to be effective in uncovering other common cause triggers. Such a test program goes far beyond what was evaluated for addressing CMDD (a one-time test program) and, based upon the work done in prioritizing this issue, would have even less justification for pursuing.

We have also considered the potential time that may be needed to develop, implement, and reach the Finding 15 resolution. Based on this timing consideration and the apparent and expected continued success of other NRC actions such as improved LER requirements, Bulletins, Information Notices, the Generic Issues Program, the SSFI Program, and the IPE Program, the detection and correction of unforeseen CMDDs may, to a significant degree, be achieved before the Finding 15 resolution can be achieved. Thus, the potential benefit in detecting and correcting unforeseen CMDDs through the Finding 15 resolution could be further reduced by the above timing considerations and success of other ongoing actions and programs. In addition, it should be recognized that these other ongoing actions and programs represent a way of uncovering and correcting CMDDs short of an integral testing program.

Based on the results and other considerations discussed above, the proposed solution to develop and implement thorough integrated systems/plant test programs under abnormal or accident conditions, as an essential and practical solution to detect and correct unforeseen CMDDs in all operating reactors, has a DROP priority ranking.

However, an alternate approach to the Finding 15 recommendation would be to assess the benefit of improvements in existing in-service, refueling, and surveillance testing programs in operating reactors, and improved startup testing for future plants. Such an assessment would focus on improvements in testing components and systems under conditions more representative of operational and DBE expectations, with emphasis directed toward detection of all types of CCFs, and not singularly CMDDs. This alternate approach, however, would be more effective as a long-term program. In this regard, the alternate approach would make use of results from the IPE program and other ongoing programs identified above. In brief, the IPE program PRA methods will include specific guidelines[1119] and procedures for treating CCFs in the plant-specific PRAs. These IPE-PRA results could be a valuable tool for identifying potential CCFs, in structuring surveillance testing strategies, and in the design of hardware and modifications, or improving operating procedures. It is planned to assess this alternate approach as an independent issue, Issue 145, "Improved Surveillance and Startup Testing Programs."

ITEM 125.I.6: VALVE TORQUE, LIMIT, AND BYPASS SWITCH SETTINGS

DESCRIPTION

Historical Background

One of the primary sources of failure of the Davis-Besse AFW isolation valves to reopen (see Issue 122.1) was ultimately traced to the torque, limit, and bypass switches which control the motor operators of the valves.[940] During the event, these valves were closed due to an operator error, shutting off all AFW flow. Once closed, the resulting high differential pressure across the closed valves necessitated a relatively large force to start valve motion. The valve motor-operator torque bypass switches were not adjusted to accommodate such a force and manual operation was needed to reopen the valves.

Issue 122.1.a, "Failure of Isolation Valves in Closed Position," deals specifically with the case of AFW isolation valves. However, at least some of the other motor-operated valves in the plant are designed by the same people that designed the AFW system and virtually all the valves in the plant are maintained by the same crews. Therefore, the problems with torque, limit, and bypass switch settings are not limited to AFW systems, but may affect any motor-operated valve in the plant. Moreover, such problems have a high potential for causing common mode failures since redundant trains are probably maintained by the same maintenance personnel.

Safety Significance

The safety concern of this issue is exactly that of IE Bulletin No. 85-03,[1036] "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings." This Bulletin required all licensees to develop and implement a program to ensure that valve operator switches are selected, set, and maintained properly for all valves in the high pressure injection, core spray and emergency feedwater systems (including BWR RCIC), that are required to be tested for operational readiness in accordance with 10 CFR 50.55a(g).

Possible Solution

IE Bulletin 85-03[1036] should resolve the safety concern of this issue for switch settings on valve operators in these specific safety systems. The extension of this issue to other valves and/or extension of the issue to more general testing adequacy also needs to be considered. However, the general question of test adequacy for all safety-related valves is the subject of Issue II.E.6.1, "Test Adequacy Study." Given the existence of II.E.6.1, there is no need to extend or generalize Issue 125.I.6.

CONCLUSION

The safety concern of this issue is being addressed by IE Bulletin 85-03[1036] and in the resolution of Issue II.E.6.1. Thus, Item 125.I.6 was DROPPED as a separate issue.

ITEM 125.I.7: OPERATOR TRAINING ADEQUACY

This item was broken down into two parts that were evaluated separately as shown below.

ITEM 125.I.7A: RECOVER FAILED EQUIPMENT

DESCRIPTION

Historical Background

This issue is based upon Finding 8 of the Incident Investigation Team's (IIT) report[886] which states:

> "The operators' understanding of procedures, plant system designs, and specific equipment operation, and operator training all played a crucial role in their success in mitigating the consequences of the event. However, if the equipment operators had been more familiar with the operation of the auxiliary feedwater pump turbine trip-throttle valve, auxiliary feedwater could have been restored several minutes sooner."

During the Davis-Besse event, both AFW turbines tripped on overspeed. These trips are not remotely resettable from the control room, but instead must be reset manually at the turbines. Two equipment operators were dispatched to the AFW turbines, but were unable to get the turbines running because they had never performed this operation before. (Hands-on practice of this task is not now a part of operator training.) The turbines were not started until after the arrival of a more experienced operator.

Safety Significance

The safety significance of this issue lies in the probability of nonrecoverability of safety systems. In many cases, a given train of a given system may trip or otherwise fail to start on first demand, but may still successfully be placed in operation by prompt, knowledgeable human intervention.

Possible Solution

TMI Action Plan Items I.A.2.2 and I.A.2.6 have addressed the issue of training and resulted in a policy statement[966] that endorsed the Institute of Nuclear Power Operations-managed training accreditation program which includes an element to ensure that feedback from operating events is included in all utility training programs. NRC monitors and evaluates industry implementation of the INPO accreditation program to ensure that: (1) plant personnel are able to meet job performance requirements; (2) training properly accounts for pertinent safety issues; and (3) mechanisms exist for upgrading and assuring the quality of training programs. Criteria to evaluate the industry training programs have been developed in NUREG-1220[993] in the resolution of Human Factors Issue HF2.1.

CONCLUSION

This issue has been resolved by the issuance of the Commission Policy Statement[966] on Training and Qualifications and by Issue HF2.1. Therefore, a new and separate issue for this concern is not warranted and the issue was DROPPED from further consideration.

ITEM 125.I.7.B: REALISTIC HANDS-ON TRAINING

DESCRIPTION

Historical Background

The issue calls for an assessment of the adequacy of hands-on training with respect to conditions that may be encountered in realistic situations, such as the loss of feedwater event that occurred at the Davis-Besse plant on June 9, 1985.[940] The assessment may involve the operator's understanding of procedures, plant systems designs, specific equipment operations, and hands-on training in handling plant transient and upset conditions.

The issue stems from Findings 8 and 16 of the NRC investigation[886] of the Davis-Besse event in which the NRC staff noted that the post-TMI improvements that focused on EOPs and training played a crucial role in mitigating the Davis-Besse event. However, if the equipment operators had been more familiar with the operations of the AFW pump turbine trip throttle valve, AFW could have been restored several minutes sooner. Also, for events such as the Davis-Besse event involving conditions outside the plant design basis (multiple equipment failures), operator training and operator understanding of systems and equipment are crucial to the likelihood that plant operators can successfully handle similar events.

Safety Significance

Assessments of the hands-on experience, referred to as performance-based training or Systems Approach to Training (SAT), are considered essential to providing assurance that nuclear power plants are operated in a safe state under all operating conditions. This issue effects all operating nuclear power plants.

Possible Solution

TMI Action Plan[48] items I.A.2.2 and I.A.2.6 included development of procedures to provide assurance that: (1) plant personnel are able to meet job performance requirements; (2) training properly account for pertinent safety issues; and (3) mechanisms exist for upgrading and assuring the quality of training programs.

To help meet these objectives, NUREG-1220[993] was developed for use by NRC personnel to review the INPO-managed performance-based training programs in nuclear power plants. NRC will continue to closely monitor the process (INPO Accreditation) and its results to independently evaluate implementation of these programs. The NRC review procedures developed in NUREG-1220[993] considered the following five elements as essential to these training programs: (1) systematic analysis of the jobs to be performed; (2) learning objectives that are derived from the analysis and that describe desired performance after training; (3) training design and implementation based on the learning objectives; (4) evaluation of trainee mastery of the objectives during training; and (5) evaluation and revisions of the training based on the performance of trained personnel in job settings (hands-on experience).

In accordance with NUREG-0985,[651] the training issues included the closeout of the following TMI Action Plan[48] items: I.A.2.2, "Training and Qualifications of Operations Personnel"; I.A.2.7, "Training Accreditation"; I.A.2.5, "Plant Drills"; and I.A.2.3, "Administration of Training Programs." The specific issue of realistic hands-on training on equipment such as AFW pumps is a performance-based element of on-the-job training (OJT). As such, mastery is determined by completion of a job qualification card to the satisfaction of a qualified OJT instructor using approved evaluation criteria. The INPO Accreditation Program is intended to provide assurance that such training is included in industry programs. NRC evaluates industry implementation of the Accreditation Program in accordance with the Policy Statement on Training and Qualification.[966]

CONCLUSION

Based on the above discussion, this issue is covered by the Policy Statement[966] on Training and Qualifications and by the Human Factors Issue HF3.1. Therefore, a new and separate issue for this concern is not warranted and the issue was DROPPED from futher consideration.

ITEM 125.I.8: PROCEDURES AND STAFFING FOR REPORTING TO NRC EMERGENCY RESPONSE CENTER

DESCRIPTION

Historical Background

This issue is based upon Finding 12 of the IIT report[886] which states:

> "The event was not reported to the NRC Operations Center in a manner reflecting the safety significance of the event. The more serious the event, the more operator involvement required to maintain plant safety. For example, if the June 9 event had been protracted, knowledgeable personnel would not have been available to maintain an open telephone line with the NRC."

Safety Significance

It is evident from the IIT report[886] of the event that there were two problems: one associated with staffing and one associated with procedures. The staffing problem was that all knowledgeable personnel were kept busy in dealing with the event. No one could be spared to keep the NRC Operations Center informed. Moreover, even if more plant staff had been available, it is likely that these additional persons would have been pressed into service for plant operations. Of course, bringing the plant to a safe condition does and should have priority. But this also calls into question the usefulness of the dedicated phone lines to the NRC Operations Center.

The procedural problem was evident in the fact that there was confusion because the emergency plan was silent on how to determine the emergency action level if the emergency classification changed during the event. Obviously, the emergency procedures contained some ambiguity.

For both problems, the result is a delay in notification of the NRC Operations Center. Although it can be argued that notification of the NRC can have little or no effect on plant events in the short term, the NRC can provide technical support and assistance over a period of several hours. Moreover, the NRC can assist in coordinating evacuations, etc., if such should ever prove necessary. Finally, the NRC has other responsibilities not directly related to plant safety but nevertheless of importance, such as providing accurate and timely information to the public, other government agencies, and the governments of other nations.

CONCLUSION

The staffing problem is a duplication[1003] of the concern of TMI Action Plan[48] Item III.A.3.4, "Nuclear Data Link." In addition, the procedural problem has already been addressed in existing regulatory requirements (10 CFR 50.72) and IE Information Notice No. 85-80. Furthermore, the IE Manual addresses the NRC regional responsibility for assuring that these reporting requirements are met.[1003]

This issue consists of two problems: the first is a duplication of TMI Action Plan[48] Item III.A.3.4 (which has been resolved) and the second has been resolved independently.[1003] Therefore, this issue was DROPPED from further consideration as a separate issue.

ITEM 125.II.1: NEED FOR ADDITIONAL ACTIONS ON AFW SYSTEMS

During the event, the main feedwater system was lost and the reactor scrammed. The AFW system should have activated and supplied feedwater to the steam generators to enable them to remove decay heat. However, during the course of the event, several failures occurred (see Issue 122) that precluded using the steam generators to remove decay heat from the primary system. The event highlighted the importance of the AFW system and also demonstrated that the AFW system might not have a reliability commensurate with its importance.[940]

If the main feedwater system shuts down for any reason, the AFW system will supply sufficient feedwater to the steam generators to remove reactor decay heat. If the AFW system were to fail also, there would be no feedwater supply at all. The steam generators would boil off their remaining liquid water inventory and then dry out. Depending on specific plant design, core uncovery will take place roughly 30 to 90 minutes after the transient begins. After steam generator dryout, there would be no decay heat removal and the continuing thermal energy production in the core would result in primary system heatup.

In most cases, the only means of decay heat removal involve use of the AFW system, recovery of the main feedwater system, or the use of feed-and-bleed techniques. Of the three means, the use of the AFW system is subject to the highest availability. The failure of the main feedwater system has roughly a 20% probability of not being recoverable in time. Moreover, use of feed-and-bleed techniques will release primary coolant to the containment necessitating extensive (and expensive) cleanup. The use of feed-and-bleed techniques, which remove decay heat by venting hot primary coolant to the containment and replacing the lost inventory in the primary system by means of the high pressure ECCS, could still prevent core uncovery. If feed-and-bleed fails, the primary system will increase in temperature and pressure to the point where the primary system safety valves open. The pressure increase will then terminate, but the primary coolant will boil off until the core is uncovered and melts.

AFW systems are safety-grade systems. In addition, the availability of feed-and-bleed techniques provides a diverse backup. Nevertheless, AFW reliability is very important for two reasons. First, loss of main feedwater is a relatively common event, occurring roughly three orders of magnitude more often than (for example) small break LOCAs. Thus, the AFW system is challenged far more often than the high pressure ECCS and therefore has a commensurately greater need for high reliability. Second, although feed-and-bleed techniques provide a backup to AFW for removing reactor decay heat, feed-and-bleed is a means of core cooling for which the plant was not designed and may have a relatively high failure probability (see Item 125.II.9). Because of these two reasons (frequent challenges and poor backup capability), it is very important that the AFW system have very high reliability.

Because loss of feedwater events are relatively frequent, the AFW system is subject to frequent challenges. Therefore, the AFW system must be characterized by very high availability. This issue consists of four parts, each of which seeks to ensure adequate AFW reliability:

(a) Two-Train AFW Unavailability
This issue is concerned that AFW systems consisting of only two-trains may not have adequate reliability.

(b) Review Existing AFW Systems for Single Failures
This issue seeks confirmatory deterministic reviews of AFW systems at operating plants to ensure that they meet the single failure criterion.

(c) NUREG-0737 Reliability Improvements
This issue proposes that PRA analyses (i.e. fault trees) be performed on AFW systems at operating plants to ensure adequate reliability.

(d) AFW Steam and Feedwater Rupture Control System/ICS Interactions in B&W Plants
This issue is concerned explicitly with a possible design problem at B&W plants.

These four parts of the issue are prioritized separately below.

ITEM 125.II.1.A: TWO-TRAIN AFW UNAVAILABILITY

DESCRIPTION

There are seven older PWRs that have two-train AFW systems. (Originally, there were more but some plants have since added a third train or made other equivalent upgrades). These AFW systems generally consist of one motor-driven train and one turbine-driven train and thus possess some diversity as well as redundancy. However, the turbine-driven trains have not proven to be as reliable as the motor-driven trains (except, of course, for the case where all AC power is lost). The more modern practice has been to use a three-train system where two trains are motor-driven and one is driven by a steam turbine. Such a system will, in principle, be more reliable than the two-train systems described above, both because of the greater redundancy of the three vs. two trains and because of the lower reliance on the steam turbine.

CONCLUSION

This issue is the same as Issue 124, "AFW System Reliability." Issue 124 will consider whether AFW system unavailability needs to be improved for plants with two-train designs.[947] Therefore, this issue was DROPPED as a separate issue.

ITEM 125.II.1.B: REVIEW EXISTING AFW SYSTEMS FOR SINGLE FAILURE

DESCRIPTION

Historical Background

The AFW system is considered an engineered safety feature and thus is required to meet the single failure criterion which can be considered a very primitive reliability requirement. An unsuspected single failure susceptibility could increase the AFW system failure probability by two orders of magnitude or more.

Safety Significance

The issue addresses the concern that there may be some unsuspected single failures which were not detected during the licensing process. Therefore, this issue proposes to re-review the AFW systems of all operating PWRs to make doubly sure that no single failures exist which by themselves could cause all AFW trains to fail.

Possible Solution

The systems to be examined have already been subjected to licensing review. Therefore, any single failures are not going to be obvious, but instead are likely to be quite subtle. Very thorough reviews will be required. It must also be remembered that AFW trains are intentionally designed to be independent. Any single failure found is most likely to be a subtle design anomaly which the designer (as well as all subsequent reviewers) failed to notice.

Several AFW systems have been examined by OIE in the course of the Safety System Functional Inspection (SSFI) program. Conversations with the SSFI team have indicated that some single failure problems as well as other potential common mode failures have been found by this program. However, these problems were not discovered by examining system design, but instead arose in the course of very thorough investigations involving extended site visits, equipment inspection, and interviews as well as design reviews. Therefore, the proposed solution is not a simple design review, but instead is a more thorough investigation along the lines of the SSFI program.

Frequency Estimate

The sequence of interest is straightforward. It is initiated by a non-recoverable loss of main feedwater. If the AFW system fails, the SUFP is not re-enabled in time, and feed-and-bleed techniques fail, core-melt will ensue. For the initiating event frequency (non-recoverable loss of main feedwater), we will use 0.64 event/RY, based upon the Oconee PRA done by Duke Power Co.[947] This figure is based upon fault tree analysis and should be reasonably representative of most main feedwater system designs.

For a three-train AFW system, a "typical" unavailability is 1.8×10^{-5}/demand.[894] The presence of a single failure susceptibility will greatly increase this figure to perhaps the square root of the original figures because half the redundancy would be removed. The change in AFW unavailability would then be about 4.2×10^{-3} failure/demand. We will assume a typical value of 0.20 for the failure probability of feed-and-bleed cooling, based upon the calculations presented under Issue 125.II.9, "Enhanced Feed-and-Bleed Capability." Multiplying these figures out, the change in core-melt frequency is:

$$(0.64/\text{year})(4.2 \times 10^{-3})(0.20) = 5.4 \times 10^{-4}/\text{year}$$

Consequence Estimate

The core-melt sequence under consideration here involves a core-melt with no large breaks initially in the reactor coolant pressure boundary. The reactor is likely to be at high pressure (until the core melts through the lower vessel head) with a steady discharge of steam and gases through the PORV(s). These are conditions likely to produce significant hydrogen generation and combustion.

The Zion and Indian Point PRA studies used a 3% probability of containment failure due to hydrogen burn (the "gamma" failure). We will follow this example and use 3%, bearing in mind that specific containment designs may differ significantly from this figure. In addition, the containment can fail to isolate (the "beta" failure). Here, the Oconee PRA figure of 0.0053 will be used. If the containment does not fail by isolation failure or hydrogen burn, it will be assumed to fail by basemat melt-through (the "epsilon" failure).

Using the usual prioritization assumptions of a central midwest plains meteorology, a uniform population density of 340 persons per square mile, a 50-mile radius, and no ingestion pathways, the consequences are:

Failure Mode	Percent Probability	Release Category	Consequences (man-rem)
gamma	3.0%	PWR-2	4.8×10^6
beta	0.5%	PWR-5	1.0×10^6
epsilon	96.5%	PWR-7	2.3×10^3

The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem.

There are 80 PWRs operating or under construction. As of March 1988 (the earliest that any hardware changes are likely to be made), these 80 plants will have a combined remaining license lifetime of 2508.4 calendar-years. At a 75% capacity factor, this is about 23.5 years of operation per plant. Thus, the estimated risk reduction associated with the possible solution to this issue is $(5.4 \times 10^{-4})(23.5)(1.5 \times 10^{-5})$ man-rem/reactor or 1904 man-rem/reactor.

Cost Estimate

The SSFI program has required about 1000 staff-hours per plant and system. This is about $50,000 of salary and overhead. In addition, hardware changes are likely to cost on the order of $100,000 per plant (i.e. more than $10,000 but less than $1,000,000) plus another $50,000 in paperwork. Thus, we will assume a cost on the order of $200,000/plant.

Value/Impact Assessment

Based on a potential risk reduction of 1,904 man-rem/reactor and a cost of $0.2M/reactor, the value/impact score is given by:

$$S = \frac{1{,}904 \text{ man-rem/reactor}}{\$0.2\text{M/reactor}}$$

$$= 9{,}520 \text{ man-rem/\$M}$$

Other Considerations

(1) The AFW system and its support systems do not contain contaminated fluids and are located outside of containment. Thus, there is no ORE associated with the fix for this issue.

(2) Averted accident costs and averted cleanup exposure are considerations, but will only drive the priority figures still higher. Thus, they will change no conclusions and will not be treated here.

(3) The high values of the parameters are predicated on finding at least one plant that needs upgrading. The SSFI personnel emphasized that this is not likely to happen without an approach similar to that of the SSFI, but such an approach is likely to bear fruit. It may be feasible to incorporate this issue into the SSFI program.

CONCLUSION

Based upon the figures generated above, this issue was given a high priority, but was later integrated into the Phase II activities scheduled for the resolution of Issue 124.[973] Thus, this issue is now covered in Issue 124.

ITEM 125.II.1.C: NUREG-0737 RELIABILITY IMPROVEMENTS

DESCRIPTION

Historical Background

After the TMI-2 accident, all PWR licensees were asked to perform an unavailability analysis of their AFW systems. This information is now somewhat out of date partly because the AFW systems were subject to some (NUREG-0737)[98] modifications after the analyses were made[946] and partly because the analyses themselves are rather primitive by modern standards.

Safety Significance

This item seeks to upgrade the AFW unavailability analyses to reflect the NUREG-0737[98] modifications and improvements and to ensure that the AFW system reliability is commensurate with the system's safety importance.

Proposed Solution

The proposed solution for this issue is to perform a PRA of all AFW systems and require modification of any systems which have an unacceptably high failure probability.

PRIORITY DETERMINATION

Issue 124, "AFW System Reliability," will consider whether seven PWRs with two-train AFW systems have AFW system unavailabilities that need to be improved. Therefore, this issue need cover only the three-train AFW systems.

To prioritize this issue, several questions need to be answered. First, how reliable must the AFW system be to have reliability commensurate with its safety importance? Generic Issue 124 has selected an unavailability of 10^{-4} failure/demand as the upper limit of acceptability.[947] We will use this same figure. The second question is, how many plants are likely to be found which cannot meet the 10^{-4} failure/demand cutoff? Analyses of ten three-train AFW designs are summarized in an RRAB memorandum[894] as follows:

Design	Failure/Demand	log(failure/demand)
Summer 1	1.2×10^{-5}	-4.92
McGuire	2.0×10^{-5}	-4.70
Comanche Peak	2.0×10^{-5}	-4.70
Diablo Canyon	3.7×10^{-5}	-4.43
San Onofre 2&3	2.2×10^{-5}	-4.66
SNUPPS	2.0×10^{-5}	-4.70
Waterford	1.4×10^{-5}	-4.85
Midland	1.0×10^{-5}	-5.00
Seabrook	2.0×10^{-5}	-4.70
Catawba	0.7×10^{-5}	-5.15

Arithmetic Mean:	1.8×10^{-5}
Arithmetic Standard Deviation:	8.4×10^{-6}
Logarithmic Mean:	-4.78
Logarithmic Standard Deviation:	0.22

These 10 analyses can be considered a statistical sample. The cutoff of 10^{-4} failure/demand is 9.76 standard deviations above the mean on a linear scale and 3.55 standard deviations above the mean on a logarithmic scale. The shape of the distribution is unknown, of course, but we will examine both a normal and a log normal distribution and use the worst case. Based upon these distributions and in the absence of any other information, if another three-train AFW design were evaluated, the probability of this new design being above the cutoff is:

Normal Distribution:	essentially zero
Log Normal Distribution:	2×10^{-4}

What this means is that 10 sample designs are all well below the cutoff. Had the sample average been close to just below 10^{-4}, one would be confident of finding a plant or two over the limit. However, the mean is far below the limit (where "far" is defined in terms of the width of the distribution) and the per-plant probability of being over the limit is small.

There are 80 PWRs operating or under construction. Seven of these have two-train AFW systems and are covered by Issue 124; this leaves 73 plants. The probability of detecting one or more of these plants with an AFW unavailability greater than 10^{-4}/demand is:

$$1 - (1 - 2 \times 10^{-4})^{73} \approx (73)(2 \times 10^{-4}) \cong 0.014$$

That is, based upon the available knowledge regarding three-train AFW designs and in the absence of other information, a PRA of all three-train AFW systems has only a few percent chance of finding a system that needs upgrading. (This does not mean that these AFW systems are problem free. It does mean that the problems probably will not be found by means of PRA, unless considerably more information is available.)

Frequency Estimate

The sequence of interest is straightforward. It is initiated by a non-recoverable loss of main feedwater. If the AFW system fails and feed-and-bleed techniques fail, core-melt will ensue.

For the initiating event frequency (non-recoverable loss of main feedwater), we will use 0.64 event/RY, based upon the Oconee PRA done by Duke Power Co.[947] This figure is based upon fault tree analysis and should be reasonably representative of most main feedwater system designs.

Next, the change in AFW failure probability must be estimated. We will assume that the AFW system "as is" has an unavailability equal to that of a "typical" two-train AFW system which would be about 6.7×10^{-4}/demand, the average of the seven plants.[948] The AFW system failure probability after upgrading would be at most 10^{-4}. Therefore, the change in probability would be about 5.7×10^{-4}.

We will assume a typical value of 0.20 for the failure probability of feed-and-bleed cooling, based upon the calculations presented under Issue 125.II.9, "Enhanced Feed-and-Bleed Capability." Multiplying these figures, the change in core-melt frequency is:

$$(0.64/\text{year})(5.7 \times 10^{-4})(0.20) = 7.3 \times 10^{-5}/\text{year}$$

The number of hypothetical plants needing modification (expectation value) is 0.014. Thus, the change in core-melt frequency for all reactors is 10^{-6}/year.

Consequence Estimate

The core-melt sequence under consideration here involves a core-melt with no large breaks initially in the reactor coolant pressure boundary. The reactor is likely to be at high pressure (until the core melts through the lower vessel head) with a steady discharge of steam and gases through the PORV(s). These are conditions likely to produce significant hydrogen generation and combustion. The Zion and Indian Point PRA studies used a 3% probability of containment failure due to hydrogen burn (the "gamma" failure). We will follow this example and use 3%, bearing in mind that specific containment designs may differ significantly from this figure. In addition, the containment can fail to isolate (the "beta" failure). Here, the Oconee PRA figure of 0.0053 will be used. If the containment does not fail by isolation failure or hydrogen burn, it will be assumed to fail by basemat melt-through (the "epsilon" failure).

Using the usual prioritization assumptions of a central midwest plains meteorology, a uniform population density of 340 persons per square mile, a 50-mile radius, and no ingestion pathways, the consequences are:

Failure Mode	Percent Probability	Release Category	Consequences (man-rem)
gamma	0.3%	PWR-2	4.8×10^{6}
beta	0.5%	PWR-5	1.0×10^{6}
epsilon	96.5%	PWR-7	2.3×10^{3}

The "weighted-average" core-melt will have consequences of 1.5×10^{5} man-rem.

Because this issue deals with only an expectation value for the number of plants, but does not necessarily expect to affect any specific plant, the per-plant parameters (core-melt/RY and man-rem/reactor) are not meaningful. Instead, the "aggregate" parameters (core-melt/year and total man-rem) are appropriate.

As of March 1988 (the earliest that any changes are likely to be made), the 73 subject plants will have a combined remaining life of 2317.8 calendar-years. At a 75% capacity factor, this works out to an average of 23.8 years of operation remaining per plant.

Therefore, the change in risk for the hypothetical plant is 11 man-rem/year and the total risk reduction for all reactors is 3.7 man-rem.

Cost Estimate

The costs involved would include administrative charges, the costs of the PRAs, and possibly costs of hardware changes, should they be required. It is not clear at this point whether the PRAs would be done by the licensees or the NRC. In any case, the cost of the PRA of one AFW system is likely to be on the order of $50,000 or more (half a staff-year). For 73 plants, this is $3.65M. We will not calculate the administrative and hardware costs, but instead will use the $3.65M as a minimum figure.

Value/Impact Assessment

Based on an estimated risk reduction of 3.7 man-rem and a minimum cost of $3.65M associated with the possible solution, the value/impact score is given by:

$$S \leq \frac{3.7 \text{ man-rem}}{\$3.65\text{M}}$$

$$\leq 1 \text{ man-rem/\$M}$$

Other Considerations

(1) The statistical logic presented above does not rule out specific systems needing attention. The proper conclusion is that, unless more information is forthcoming (for example, specific design or performance problems), a non-specific general search such as this is difficult to justify because there is no specific reason to believe a problem will be found this way, based on past experience. Also, the continuous distribution assumption implies that design anomalies, such as the single failures of Item 125.II.1.B, have been fixed. This item must not be viewed in isolation.

(2) Issue 124, "AFW System Reliability," in addition to its attention to plants with two-train AFW systems, also is considering whether to require confirmation that the remaining PWRs have AFW system reliabilities that are less than 10^{-4}/demand. However, Issue 124 has not produced a decision at this time, nor does a decision appear to be forthcoming in the near future. Therefore, this issue cannot be subsumed within Issue 124.

(3) In most cases, the fix will not involve work within radiation fields and thus will not involve ORE.

(4) The ORE averted due to post-feed-and-bleed cleanup and post-core-melt cleanup is a minor consideration. ORE associated with cleanup is estimated to be 1800 man-rem after a primary coolant spill and 20,000 man-rem after a core-melt accident.[64] If the frequency of feed-and-bleed events

is 5 x 10^{-6}/year, the actuarial cleanup ORE averted is only 0.2 man-rem. Similarly, a total core-melt frequency of 10^{-6}/year corresponds to an actuarial averted cleanup ORE of only 0.5 man-rem. If averted ORE were added to the man-rem/reactor and man-rem/$M figures above, no conclusions would change.

(5) The proposed fix would reduce core-melt frequency and the frequency of feed-and-bleed events and, therefore, would avert cleanup costs and replacement power costs. The cost of a feed-and-bleed usage is dominated by roughly six months of replacement power while the cleanup is in progress. If the average frequency of such events is 5 x 10^{-6}/year and the average remaining lifetime is 31.7 calendar-years at 75% utilization, then making the usual assumptions of a 5% annual discount rate and a replacement power cost of $300,000/day, the actuarial savings for feed-and-bleed cleanup are $3,300. Similarly, the actuarial savings of averted core-melt cleanup (which is assumed to cost one billion dollars if it happens) are about $12,000. The actuarial savings from replacement power after a core-melt up to the end of the plant life are also about $12,000. (This last figure represents the lost capital investment in the plant.) If these theoretical cost savings were subtracted from the expense of the fix, the man-rem/$M would not change significantly.

CONCLUSION

Based upon the figures above, this issue was DROPPED from further consideration.

ITEM 125.II.1.D: AFW STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM/ICS INTERACTIONS IN B&W PLANTS

DESCRIPTION

This issue is centered upon the subject of the reliability of the AFW system which is safety-grade. This item is targeted specifically at B&W plants[940] and would require a reexamination of the AFW system reliability.[948] The reasons given are two-fold. First, assessments made shortly after the TMI accident indicated that the AFW system in B&W plants had (at that time) an unavailability approximately an order of magnitude higher than those in most other PWRs.[948] (This does not account for the subsequent modifications to these AFW systems.) Second, this item calls for explicit attention to the interactions between the AFW system and the Steam and Feedwater Rupture Control System (SFRCS) and between the AFW system and the Integrated Control System (ICS). Such interactions are important because the initiating transient may well be caused by a problem with the ICS and any possible interactions between the ICS and AFW or SFRCS would be a potential source of a common mode failure, defeating the system needed to mitigate the transient.

PRIORITY DETERMINATION

On the general question of AFW unavailability, the B&W plants have already updated their reliability analyses to reflect the post-TMI modifications.[946] These updates have satisfied the original concern.[949]

The specific issue of the ICS-SFRCS-AFW interactions deserves more discussion. The function of an SFRCS is to control the AFW system. The name (Steam and Feedwater Rupture Control System) is somewhat misleading in that the SFRCS also initiates AFW for loss of main feedwater events. Those plants with an SFRCS should have no interactions between the ICS and the SFRCS or AFW systems.

There are some B&W plants that have used the ICS to control the AFW system. Of these, two plants (Crystal River and ANO-1) have installed an "Emergency Feedwater Initiation and Control (EFIC) System" to replace the ICS as the control system for AFW. (The EFIC system is an improvement over SFRCS in that the EFIC system will not allow both steam generators to be isolated simultaneously. The SFRCS at Davis-Besse has also been modified such that it will no longer allow both steam generators to be isolated simultaneously.) Of the two remaining plants, Rancho Seco will install an EFIC system at its next refueling outage and TMI-1 will install a system similar to EFIC, but designed by the licensee, at its next refueling outage.

Under these circumstances, the concern is not with SFRCS-AFW interactions, but instead reduces to ensuring that there is no interaction between the ICS and the AFW or its control system that can cause a common mode failure. For plants with two-train AFW systems, this will be covered by the analyses of Issue 124.[947,949] The remaining plants will be examined under the B&W Reassessment Program which places considerable emphasis on the ICS.[950]

CONCLUSION

This item is covered in Issue 124 and the B&W Reassessment Program and was DROPPED as a separate issue.

ITEM 125.II.2: ADEQUACY OF EXISTING MAINTENANCE REQUIREMENTS FOR SAFETY-RELATED SYSTEMS

DESCRIPTION

Historical Background

The objective of this issue is to assess the adequacy of existing maintenance requirements and their impact on the reliability of safety-related systems.[940] The IIT concluded that the underlying cause of the Davis-Besse event was the licensee's lack of attention to detail in the care of plant equipment.[886]

Safety Significance

Inadequate and/or improper maintenance of equipment, components, and systems relied on for safe operations of the plants can lead to loss of safety functions. The loss of safety functions of the safety-related systems can increase the severity of transients and lead to severe core damage and possibly a core-melt. Given a core-melt and loss of containment integrity, public radiation exposure would result from the release of fission product materials. The issue is applicable to all operating nuclear power plants.

Possible Solutions

For the Davis-Besse plant, the staff conducted a maintenance survey consistent with the NRC Maintenance and Surveillance Program Plan (MSPP) as a result of the IIT conclusions.[886] As a result of the survey, the staff identified a number of weaknesses impeding the conduct of maintenance activities at the Davis-Besse plant.[1011] A subsequent NRC follow-up survey of the Davis-Besse maintenance activities in March 1986 indicated that the licensee had made considerable progress in all maintenance areas except maintenance backlog since the previous survey. Particular strengths noted were in the areas of maintenance training, spare parts, and material readiness. Based on the results of the March 1986 survey, the NRC concluded that the Davis-Besse new maintenance organization was functioning as planned, and no major identifiable weaknesses were evident. The few remaining problem areas noted by the staff were not considered programmatic weaknesses that would adversely affect the functioning of the maintenance organization.[1011]

In response to Issue 3 of the Commission Policy and Planning Guidance,[210] the staff developed the MSPP that consisted of two phases: Phase I and Phase II. The findings of the Phase I activities are reported in NUREG-1212.[1013] Essentially, the Phase I objectives (which are complete) have addressed the objectives of this issue. In brief, Phase I of the MSPP was designed to survey current maintenance practices in the nuclear utility industry, evaluate their effectiveness, and address the technical and regulatory issues of nuclear power plant maintenance.

Thirty-one measures of maintenance were developed for Phase I of the MSPP. These measures were then organized into the following five categories: (1) overall system/component reliability; (2) overall safety system reliability; (3) challenges to safety systems; (4) radiological exposure; and (5) regulatory assessment. An analysis of the overall trends and patterns across the above five categories of maintenance revealed several important trends. In general, although plant maintenance performance showed some improvement from 1980 to 1985, the safety systems reliability for all plants did not significantly change since 1981. Thus, the contribution of maintenance to reliability problems indicated that some maintenance programs and practices are not effective. The Phase I findings confirmed that there are wide variations in maintenance practices among utilities and the industry has established a variety of programs aimed at self-improvement that do not appear to be well-integrated or effectively implemented in some cases. The resolution of the issues identified in Phase I of the MSPP will be addressed in Phase II of the MSPP.

The Phase II activities of the MSPP are being addressed under Issue HF8. In brief, Phase II of the MSPP requires the staff to: (1) gather data to support a definition of the role of maintenance in safety; (2) develop goals for plant reliability in ensuring effective maintenance; (3) assess data to determine performance-oriented maintenance criteria; (4) make recommendations for endorsement of good maintenance practices; (5) recommend improvements to the maintenance/operations interface; (6) provide input to draft industry standards for maintenance; and (7) assess industry programs in self-improvement of maintenance programs.

CONCLUSION

The maintenance-related problems identified by the NRC IIT for the Davis-Besse plant were resolved.[1011] For all operating plants, the objectives of this issue were essentially completed by Phase I of the existing MSPP. Phase II of the MSPP (Issue HF8) will follow up and address problem issues identified in Phase I of the MSPP that warrant further NRC and industry actions.[1013] Therefore, this issue was DROPPED as a separate issue.

ITEM 125.II.3: REVIEW STEAM/FEEDLINE BREAK MITIGATION SYSTEMS FOR SINGLE FAILURE

DESCRIPTION

Historical Background

During the investigation of the Davis-Besse event, the importance of the SFRCS became evident. Although the name of this system implies that its purpose is to mitigate steam and feedwater line breaks, in actual practice this is the AFW control system. Thus, the functions of this control system are more general than the name implies.

Safety Significance

Steam/feed line break mitigation systems vary in title and in detailed design from plant to plant and from vendor to vendor. However, they are generally composed of two logic trains in order to meet the single failure criterion. The presence of an unsuspected single failure would have the potential to greatly increase the probability of system failure. This has safety significance for several accident scenarios.

First, the reliability of mitigation of a steam or feedwater line break would be adversely affected. During such an event, the mitigation system isolates both the steam line and the feedwater (main and auxiliary) lines associated with the depressurizing steam generator. For most breaks outside containment, this stops the blowdown. For a break inside containment, the secondary side of the affected steam generator will blow down to the containment atmosphere, but isolation of feedwater to the affected steam generator will prevent continued long-term steaming due to decay heat from the reactor core. This is necessary to ensure that the containment design pressure is not exceeded.

This scenario is also the concern of Issue 125.II.7, "Reevaluate Provision to Automatically Isolate Feedwater from Steam Generator During a Line Break." The safety concern expressed here is not a duplication of Issue 125.II.7; rather, Issue 125.II.7 questions the necessity of having this automatic isolation provision and thus is opposite in its thrust. Nevertheless, a detailed examination of the significance of this scenario is presented in the prioritization of Issue 125.II.7 and will not be treated further here.

The second scenario is the loss of feedwater transient. If main feedwater is lost and not readily recoverable and a single failure in the AFW control system defeats AFW, most plants will have to use feed-and-bleed core cooling techniques to prevent core-melt. Because the viability of feed-and-bleed cooling is often questionable, and because non-recoverable loss of main feedwater events have in fact occurred many times, the reliability of the AFW system and its control system is of considerable importance. This is exactly the safety concern of Issue 125.II.1.b, "Review Existing AFW Systems for Single Failure." Thus, this safety concern is a duplicate of Issue 125.II.1.b.

The third scenario is specific to B&W plants. These plants provide AFW to the steam generators by means of a special AFW sparger. This sparger is located high in the steam generator and sprays water onto the steam generator tubes. The advantage of this arrangement is that it enhances natural convection through the primary system when forced circulation is lost. If a loss of forced circulation (i.e. trip of all four reactor coolant pumps) transient were to occur and AFW were to fail, natural circulation might not provide sufficient core cooling to prevent cladding failure, even if some feedwater were being supplied to the secondary side of the steam generators. This is somewhat different from the safety concern of Issue 125.II.1.b which is concerned with AFW reliability during loss of feedwater transients. Nevertheless, any upgrades brought about by the resolution of Issue 125.II.1.b should address the loss of forced circulation concern as well. Therefore, this concern is also covered by Issue 125.II.1.b.

CONCLUSION

This issue has three aspects: (1) line break mitigation, which is covered in Issue 125.II.7; (2) loss of feedwater, which is covered in Issue 125.II.1.b; and (3) loss of forced circulation, which is also covered in Issue 125.11.1.b. Therefore, this item was DROPPED as a new and separate issue.

ITEM 125.II.4: THERMAL STRESS OF OTSG COMPONENTS

DESCRIPTION

Historical Background

This issue addresses the effects of thermal stresses induced on the OTSG from a loss of feedwater transient and was based on RES concerns.[941,942]

Safety Significance

The safety concern raised was that the introduction of the recovered feedwater to the dry OTSG, following the Davis-Besse transient, may have degraded the structural integrity of the OTSG and the steam generator tubes. The resulting transient-induced thermal stresses might lead to increased rupture frequencies for the steam generator components which, in turn, would increase the plant's core-melt frequency and the potential radiological risks to the public.

PRIORITY DETERMINATION

Following the Davis-Besse transient, the staff reviewed[943] the B&W analysis regarding the possible effects of the transient to the structural integrity of the Davis-Besse OTSG. Comparisons were made between the Davis-Besse event and the B&W design basis analyses. Therefore, the conclusions reached herein are considered applicable to similar transients of similar OTSGs (B&W) plants.

This issue is not applicable to CE or :• PWR plants that have U-Tube heat exchanger designs and AFW injection that does not spray directly on the steam generator tubes.

The following components were considered to be the most highly stressed during transients involving boiled-dry OTSGs and subsequent recovery of auxiliary and main feedwater: (1) AFW Nozzle, (2) Main Feedwater Nozzle, (3) AFW Jet Impingement on Steam Generator Tubes, (4) Stresses on Steam Generator Tubes Due to Steam Generator Shell/Tube Thermal Stress, (5) Degraded Steam Generator Tubes, and (6) Thermal Shock of Lower Tube Sheet.

AFW Nozzle: The stress and fatigue analyses of the AFW nozzle resulting from the Davis-Besse transient were compared to the original design basis temperature difference of 530°F between the hot steam generator shell and the AFW injection temperature. During the transient, the temperature difference was 501°F which is within the design basis analyses. The fatigue usage factor that was predicated on 875 AFW initiations, was also considered acceptable.[943]

Similar design basis analyses are conducted for all B&W OTSG designs except that the numbers of transients and nozzle designs are plant-specific.[945] Therefore, the thermal stresses and fatigue component resulting from similar events are bounded by the original B&W design basis analyses.

Main Feedwater Nozzle: The original design basis stress analysis for the Davis-Besse OTSG was based on a temperature difference of 445°F between the main feedwater nozzle and the feedwater. During the Davis-Besse transient, the temperature difference was approximately 162°F.[943] Therefore, the thermal stresses and fatigue factor resulting from the transient were considered bounded by the original B&W design basis. Similar design analyses are conducted for all B&W OTSG designs with the same exceptions as noted for the AFW nozzles.[945]

AFW Jet Impingement on Steam Generator Tubes: The original design basis assumed a temperature difference of 586°F between the AFW coolant and the steam generator tube surfaces. Based on thermocouple data, the temperature difference between the steam generator tubes and the AFW was determined to be approximately 523°F.[943] Therefore, the thermal stresses and the fatigue factor (based on 29,400 cycles in the original Davis-Besse OTSG design basis) resulting from the transient were considered bounded by the original B&W design basis. Similar analyses (with the exception of the number of transients) have been conducted for all B&W OTSGs.[945]

Steam Generator Shell/Tube Thermal Stress: Temperature differences between both steam generator shells and their tubes and the pressure differences across the tube sheets were analyzed based on thermocouple readings. The maximum temperature difference in one of the two steam generators was estimated to be approximately 72°F. The resulting stresses and fatigue component were determined to be acceptable by the staff.[943]

Degraded Steam Generator Tubes: In NUREG-0565,[96] the staff discussed its evaluation of B&W's analyses of potential defective steam generator tubes with up to 70% through-wall defects. The B&W thermal stress conditions included ten transients with maximum flaw orientations following a SBLOCA. The secondary side was postulated to have boiled dry and the primary system was significantly voided. The cold AFW impinging on the steam generator tubes and the pressure loads resulting from the tube-to-shell temperature differences, in combination with the potential effects of slug flow in the steam generator tubes from the voiding primary system, was evaluated. The staff concluded that the combination of conservative analyses and the test results provided assurance that structural integrity of the primary coolant pressure boundary (steam generator tubes) would be maintained.

Thermal Shock of Lower Tube Sheet: The stress and fatigue analyses relative to thermal shock of the lower tube sheet from the Davis-Besse transient were reviewed by the staff. The stresses and fatigue usage factor resulting from the transient were determined to be negligible. Therefore, it was concluded that the tube sheet was essentially unaffected by the Davis-Besse transient.[943]

CONCLUSION

The staff has raised concerns relative to potential beyond design basis conditions that may increase the primary system temperatures above those previously analyzed. The higher superheat temperatures will lower the steam generator tube strength or, in combination with injected cold AFW temperature, might increase the thermal stresses. These conditions might then further degrade or fail the primary pressure boundary. This potential phenomenon is being studied by the staff.[944]

The staff concluded that transients similar to the Davis-Besse transient are bounded by the original B&W design basis analyses. Therefore, the B&W OTSG design basis adequately accounts for such anticipated operational occurrences. Based on the staff findings, this issue involves no increase in risk to the public and was DROPPED from further consideration.

The potential superheat phenomena being studied by the staff is beyond the current design basis. Should the results of the superheat studies indicate a need for changes in the design basis of the primary and secondary pressure boundaries, it is recommended that any follow-up effort be prioritized as a new and separate issue.

ITEM 125.II.5: THERMAL-HYDRAULIC EFFECTS OF LOSS AND RESTORATION OF FEEDWATER ON PRIMARY SYSTEM COMPONENTS

DESCRIPTION

Historical Background

The Davis-Besse plant recovered feedwater flow following the loss of feedwater transient on June 9, 1985. With the loss of feedwater to the steam generators, heatup of the reactor coolant system peaked at about 592°F and then, following recovery of the feedwater, decreased to 540°F in approximately six minutes (normal post-trip average temperature is 550°F). Thus, the reactor coolant system experienced an overcooling transient rate of 520°F/hr for the 6-minute time interval.

Due to concerns identified,[941,942] the staff was requested[940] to review and evaluate the safety significance of the thermal-hydraulic effects (potential pressurized thermal shock) to reactor pressure vessels, nozzles, and downcomer surface areas from such overcooling transients.

Safety Significance

The potential for pressurized thermal shock (PTS) to the reactor pressure vessel (RPV) and components from overcooling transients is more critical to PWRs by virtue of their designs. Therefore, this issue is applicable to all PWRs. With increased neutron radiation exposure, the temperature at which the RPV materials fracture toughness decreases to unacceptable limits increases. Thus, with time (neutron radiation exposure), the magnitude of the thermal stresses which are also compounded by pressure-induced stresses during overcooling transients, could approach reduced fracture toughness capabilities of the RPV materials.

Structural failure (fracture) of the RPV, to an extent that would make the RPV unable to contain sufficient water to cover the reactor core, would result in a core-melt. Given a core-melt and subsequent loss of containment integrity, public radiation exposure would result from the release of fission product materials.

Possible Solutions

For the Davis-Besse plant, the staff reviewed and evaluated the licensee's PTS calculations and results related to the June 9, 1985 event. Based on the staff's findings,[1011] the temperature of the limiting weld in the Davis-Besse RPV would have had to drop an additional 377°F to cause crack-initiation to become a significant PTS event.

To ensure that nuclear power plants do not operate with unacceptable PTS risks, the NRC promulgated a final rule[1012] in July 1985 that amended its regulations to: (1) establish a screening criterion related to the fracture-resistance of PWR vessels; (2) require analyses and a schedule for implementation of neutron flux reduction programs to avoid exceeding the screening criterion; and (3) require detailed safety evaluations to be performed before plants commence operations beyond the screening criterion. The final PTS rule was a result of extensive analyses performed by the NRC staff (USI A-49, "Pressurized Thermal Shock") and several industry groups. The analyses covered all conceivable PTS events, including RPV overcooling transients, that were more severe than the Davis-Besse event.

CONCLUSION

The PTS concern from the Davis-Besse event was resolved in NUREG-1177.[1011] All other conceivable PTS concerns were addressed in the resolution of USI A-49 and the final PTS rule.[1012] Therefore, this issue was DROPPED as a separate issue.

ITEMS 125.II.6: REEXAMINE PRA ESTIMATES OF CORE DAMAGE RISK FROM LOSS OF ALL FEEDWATER

DESCRIPTION

The memorandum which initiated this action recommends that plant-specific reliability data be solicited from Toledo Edison Company (the licensee for Davis-Besse).[1004] This information would then be used by the NRC staff to formulate a new and revised model for estimating the frequency of severe accidents involving loss of main feedwater at the Davis-Besse plant. The purpose of this effort was to provide information, in addition to the results of deterministic reviews, to aid in decision-making concerning the restart of the Davis-Besse plant.

CONCLUSION

This task is a legitimate action on the Davis-Besse unit, but is not intended to address other plants since they are not in need of a restart decision. Therefore, the issue is not generic but is specific to one unit. However, before dismissing the issue, its generic potential should be explored: What benefits would be reaped if other plants were investigated and modeled with plant-specific data? Evaluations of plants with two-train AFW systems are being made in the resolution of Issue 124, "AFW System Reliability," and investigations along this line for all plants are also being considered. In addition, Issue 125.II.1.b, "Review Existing AFW Systems for Single Failure," deals with gathering of plant-specific information and Issue 125.II.1.c, "NUREG-0737 Reliability Improvements," deals with specific AFW system reliabilities. Finally, USI A-45, "Shutdown Decay Heat Removal Requirements," deals with the question of plant safety for events (such as loss of all feedwater) where the plant's heat sink is lost. In view of the existence of all these issues, there is little to be gained by generalizing this new proposed action to form an additional generic task. As a result, this issue was placed in the DROP category.

ITEM 125.II.7: REEVALUATE PROVISION TO AUTOMATICALLY ISOLATE FEEDWATER FROM STEAM GENERATOR DURING A LINE BREAK

DESCRIPTION

Historical Background

During the course of the investigation of the event, it was pointed out that the benefits of AFW isolation are probably more than outweighed by the negative aspects of this feature.[940,951]

Safety Significance

The automatic isolation of AFW from a steam generator is provided to mitigate the consequences of a steam or feedwater line break. The isolation logic, usually triggered by a low steam generator pressure signal, closes all main steam isolation valves and also isolates AFW from the depressurizing steam generator. (The AFW flow is diverted to an intact steam generator.) The purposes of the AFW isolation are three-fold:

(1) The break blowdown is minimized. Shutting off AFW will not prevent the initial secondary side inventory from blowing down. However, the isolation will prevent continued steaming out of the break as decay heat continues to produce thermal energy.

(2) Overcooling of the primary system is reduced. As the depressurizing steam generator blows down to atmospheric pressure, the primary system is cooled down, causing primary coolant shrinkage and (if the event occurs near the end of the fuel cycle) a return to criticality, which adds a modest amount of thermal energy to the transient. Shutting off feedwater to the faulted steam generator will reduce this effect, although once again the initial blowdown will be the dominant factor.

The significance of these first two considerations is in containment pressure. The containment is designed to accommodate a primary system blowdown followed by decay heat boiloff (the large break LOCA). A steam or feedwater line break within containment might cause the containment design pressure to be exceeded if the AFW isolation were not present.

(3) The AFW isolation is needed to divert AFW flow to the intact steam generator(s). For the case of a two-loop plant with a two-train AFW system, this is needed to meet the single failure criterion in supplying feedwater to the intact steam generator. (The situation becomes more complex for other cases, e.g. a four-loop plant with a three-train AFW system.) Note that, unless the line break is in the AFW line, core cooling would still meet the single failure criterion even without the isolation, since the faulted steam generator would still be capable of heat transfer.

In summary, the automatic isolation is needed only to help mitigate a relatively rare event (steam or feedwater line break) and even then is only remotely connected with sequences leading to core-melt.

In contrast, this isolation has definite disadvantages. If both channels of the controlling system were to spontaneously actuate during normal operation, all AFW would be lost and the MSIVs would close. Most newer plants use turbine-driven main feedwater pumps. Thus, main feedwater would be lost also. If the plant operators fail to correctly diagnose and correct the problem, only feed-and-bleed cooling would be available to prevent core-melt. Similarly, if spurious AFW isolation were to occur during the course of another transient, once again only feed-and-bleed cooling would be available to prevent core-melt.

The long-term success of AFW for main feedwater transients, steam generator tube ruptures, and small LOCAs may also be compromised.[951] During controlled cooldown, the thresholds for automatic AFW isolation are crossed. Procedures call for operators to lock out the isolation logic as the steam generator pressure approaches the isolation setpoint. Under the circumstances, the accompanying distractions make it possible that the operators will forget to override the AFW isolation logic in the permissive window. Thus, AFW reliability in these scenarios may be significantly degraded.

The safety significance of this issue arises from the fact that the negative aspects involve accident sequences which have more frequent initiators, and more significant consequences, than those of the positive aspects.

Possible Solution

A very straightforward solution has been proposed: simply disconnect the AFW isolation valve actuators from the automatic logic and depend on plant procedures, i.e., have the operators close the AFW isolation valves (by remote manual operation from the control room) in the event of a line break.[951] These procedures would require careful verification of the existence of a line break before isolating a steam generator from AFW.

PRIORITY DETERMINATION

Frequency Estimate

It is necessary to calculate estimates of both the positive and negative aspects of disabling the automatic AFW isolation. The positive aspects are due to a decrease in the frequency of loss of all feedwater events. There are three accident sequences of interest.

(1) The first sequence is initiated by a spontaneous actuation of both channels of the isolation logic. (We will assume a two-loop plant design for prioritization purposes.) There is no data readily available for such actuations. However, it is possible to make an educated guess. EPRI NP-2230[307] provides some perspective, based upon actual experience with other systems:

Inadvertent Safety Injection Signal, PWR	0.06/RY
MSIV Closure, PWR	0.03/RY
Steam Relief Valve Open, PWR	0.04/RY
Inadvertent Startup of BWR HPCI	0.01/RY

Based upon these figures, it is expected that spontaneous actuations will occur with a frequency on the order of 0.03/RY. Of course, this would isolate only one steam generator. However, such systems generally have a common mode failure probability on the order of 5%. (In addition, the second train of AFW has an unavailability due to other causes of roughly 1%. However, the main feedwater system would still be available in this case.) Thus, the frequency of both steam generators isolating is (0.03/RY)(0.05), or 1.5×10^{-3}/RY. Of course, the plant operators are likely to reset the logic and turn the transient around. We will assume a 1% (minimum) failure probability for recovery by operator action. This leaves feed-and-bleed cooling for which we will assign a typical failure probability value of 0.20 and a maximum failure probability of 0.60, based on the calculations presented under Item 125.II.9, "Enhanced Feed-and-Bleed Capability." Multiplying these figures gives a core-melt frequency of 3×10^{-6}/RY typical, 9×10^{-6}/RY maximum.

(2) The second sequence is initiated by another, independent transient. During the course of this transient, and the consequent perturbation of a great many plant systems, the AFW isolation logic is triggered. The MSIVs close, causing a loss of main feedwater (if main feedwater has not previously been lost), and the AFW isolates. Again, unless the AFW isolation valves are reopened, only feed-and-bleed is available as a means of core cooling.

The AFW isolation logic can be triggered during a transient in two ways. The first is by some type of inadvertent systems interaction, e.g., electromagnetic coupling. The proper fix for this problem is to eliminate the systems interaction which may well have other consequences in addition to AFW isolation. Therefore, this effect will not be considered here.

The second way to trigger AFW isolation is by the actual existence of low pressure in the secondary system, caused by the initiating transient. In this case, the isolation is working as designed (but not as intended). Low pressure transients are relatively rare, since the steam space in question is usually right on top of a significant quantity of water at saturation temperature. Low pressure will occur only if steam is vented at a rapid rate in sufficient quantity to cool the water inventory via boiloff to the point where saturation pressure drops below the AFW isolation setpoint. The other possibility is a dryout of the steam generator.

This is possible for B&W plants because of the relatively low water inventory in the steam generators. However, such an event in a Westinghouse or CE plant would probably imply that the main feedwater and AFW had already failed.

There is no readily available way of estimating the probability of a pressure drop, given a transient. However, EPRI NP-2230[307] gives a frequency of 0.04/RY for events where PWR steam relief valves open. Thus, we can assume that depressurization events occur with at least this frequency. If we further assume that perhaps 10% of these pressure drops are deep enough to trigger AFW isolation, and again assume a 1% probability of failure of the operators to recover AFW, the resulting core-melt frequencies are 8×10^{-6}/RY typical, 2.4×10^{-5}/RY maximum.

(3) The third sequence involves the long term success of AFW for main feedwater transients. During controlled cooldown, the thresholds for automatic AFW isolation are crossed. Procedures call for the operators to lock out the isolation logic as the steam generator pressure approaches the setpoint. If the operators fail to do so, both trains of AFW will isolate. Main feedwater is also unavailable, since its loss initiated the transient. Again, only feed-and-bleed would be available for core cooling.

Non-recoverable loss of main feedwater events are estimated to occur with a frequency of 0.64/RY.[952] We will assume a 1% minimum probability of operator failure to bypass the isolation logic and another 1% minimum probability of failure of the operators to recover the AFW system. In addition, there is still feed-and-bleed cooling which, because the plant is already partially cooled down, should have a better than usual chance of succeeding. We will therefore assume 10% instead of 20% or 60% for feed-and-bleed failure probability. The result is a core-melt frequency of 6.4×10^{-6}/RY.

The three sequences above add up to a "typical" core-melt frequency of 1.7×10^{-5}/RY and as much as 3.9×10^{-5}/RY for a plant with marginal feed-and-bleed capability. Now we must estimate the negative aspects of the proposed fix.

The first negative scenario is the feedwater line break. Here, a break in the feedwater line to one steam generator initiates the sequence. With the proposed fix, the line is not isolated and one train of AFW simply pumps water out of the break. If the operator fails to manually isolate the break, the remaining AFW train fails, and feed-and-bleed techniques fail, core-melt will result.

Steam and feedwater line breaks are estimated to occur at a combined rate of 10^{-3}/RY (see Issue A-22). Because steam lines are larger and not as subject to water hammer phenomena, the feedwater lines are expected to be more likely to break than the steam lines. We will therefore assume that feedwater lines will break with a frequency of 9×10^{-4}/RY, i.e. 90% of the total line break frequency.

The unaffected single train of AFW should have a failure probability on the order of 0.01 or less. Consistent with the positive scenario calculations, we will assume a 1% probability of operator failure to manually isolate the affected steam generator and a 20% typical, 60% maximum feed-and-bleed failure probability. The product is a core-melt frequency of 1.8×10^{-8}/RY typical and 5.4×10^{-8}/RY maximum.

The remaining scenario is a steam line break. This scenario may involve the theoretical possibility of containment failure by overpressure, but does not lead to core-melt. We will assume a 10^{-3}/RY frequency of line break as before and a 10% probability that the line break is in the steam lines as opposed to the feedwater line breaks of the previous scenario. Once again, the probability of the operator to fail to manually isolate is assumed to be 1%. The frequency of higher than expected containment pressure due to long term steaming in the faulted steam generator is then 10^{-6}/RY.

The change in core-melt frequency is the algebraic sum of the various scenarios:

	Core-melt Averted/RY	
	Typical	Maximum
Spontaneous Actuation	3.0×10^{-6}	9.0×10^{-6}
Transient Initiated	8.0×10^{-6}	2.4×10^{-5}
Cooldown Initiated	6.4×10^{-6}	6.4×10^{-6}
Feedwater Line Break	-1.8×10^{-8}	-5.4×10^{-8}
Net change in core-melt frequency	1.7×10^{-5}	3.9×10^{-5}

The estimated reduction in core-melt frequency for all reactors is 3.5×10^{-4}/year.

Consequence Estimate

The core-melt sequences under consideration here involve a core-melt with no large breaks initially in the reactor coolant pressure boundary. The reactor is likely to be at high pressure (until the core melts through the lower vessel head) with a steady discharge of steam and gases through the PORV(s). These are conditions likely to produce significant hydrogen generation and combustion.

The Zion and Indian Point PRA studies used a 3% probability of containment failure due to hydrogen burn (the "gamma" failure). We will follow this example and use 3%, bearing in mind that specific containment designs may differ significantly from this figure. In addition, the containment can fail to isolate (the "beta" failure). Here, the Oconee PRA figure of 0.0053 will be used. If the containment does not fail by isolation failure or hydrogen burn, it will be assumed to fail by basemat melt-through (the "epsilon" failure).

Using the usual prioritization assumptions of a central midwest plains meteorology, a uniform population density of 340 persons per square mile, a 50-mile radius, and no ingestion pathways, the consequences are:

Failure Mode	Percent Probability	Release Category	Consequences (man-rem)
gamma	3.0%	PWR-2	4.8×10^6
beta	0.5%	PWR-5	1.0×10^6
epsilon	96.5%	PWR-7	2.3×10^3

The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem/event.

These figures should cover all PWRs with large dry containments. They do not apply to ice condenser containments. Because of the low free volume in such a containment, failures due to overpressure are more likely and the averaged consequences may be significantly greater. However, we are not aware of any ice condenser plant which has an automatic AFW isolation affected by this issue.

The steam-line-break/containment-rupture scenario is different. The containment pressure is unlikely to exceed the design pressure by more than a few percent, if at all. In most cases, the containment is calculated to fail at 2 to 2.5 times its design pressure. Therefore, containment failure by overpressure is at most a very remote theoretical possibility. We will assume that the overpressure failure probability cannot be greater than 3%, the hydrogen burn figure (a highly conservative assumption). The only radioactive release comes from the containment atmosphere and any primary coolant leakage or discharge from the PORV(s). We have no consequence estimates for such an event. However, the consequences can be conservatively bounded by those of a PWR-8 event, which is a successfully mitigated LOCA with failure of the containment to isolate. The PWR-8 consequences are 7.5×10^4 man-rem. Thus, the steam line break event will have "average" consequences of at most $(0.03)(7.5 \times 10^4)$ or 2250 man-rem, and probably much less.

It is not known how many plants are affected by this issue. In many plants, the AFW isolation logic has provisions to prevent isolation of feedwater to more than one steam generator. Others may not even have this isolation logic. We will assume that about 25% of the PWRs will be affected by this issue. There are 83 PWRs and, as of spring 1987 (the earliest that this issue is likely to result in changes), the remaining collective calendar life will be 2571 RY. At a 75% utilization factor, this is 1928 RY or about 23 operational years per reactor.

The net change in man-rem/RY is obtained by multiplying the change in core-melt frequency by 1.5×10^5 man-rem (average) per core-melt. Then, the steam line break scenario must be subtracted. The consequences of the steam line break scenario (upper bound) are simply (10^{-6} overpressure/RY) [2250 (average) man-rem/overpressure], or 2.3×10^{-3} man-rem/RY.

	Change in man-rem/RY	
	Typical	Maximum
Core-melt Scenarios	2.6	5.9
Steam Line Break	≤0.0023	≤0.0023
Net change:	2.6	5.9

The estimated risk reduction is 140 man-rem/reactor (maximum) and 1,300 man-rem for all reactors.

Cost Estimate

The proposed fix for this issue is simply to remove some leads from some equipment, an action which is likely to be more than paid for by decreased maintenance and testing. Nevertheless, even a relaxation of requirements as this w' ' require review of each affected plant's isolation logic, to be certain that the net effect is an increase in plant safety. In addition, technical specification and procedural changes, with their associated paperwork, will be necessary. We will assume per plant costs of $32,000 to the industry and $25,000 to the NRC, which are typical for a complicated and controversial technical specification change. Thus, the estimated total cost associated with the resolution of this issue is (0.25)(83)($0.057M) or $1.18M.

Value/Impact Assessment

Based on an estimated risk reduction of 1,300 man-rem and a cost of $1.18M, the value/impact score is given by:

$$S = \frac{1300 \text{ man-rem}}{\$1.18M}$$

$$= 1102 \text{ man-rem/\$M}$$

Other Considerations

(1) It should be noted that the maximum values are based upon a plant with marginal feed-and-bleed capability. The subset of PWRs which are affected by this issue may not include such a plant. Thus, the "maximum" plant may not exist.

(2) The proposed fix does not involve work within radiation fields and thus does not involve ORE. However, the ORE averted due to post feed-and-bleed cleanup and post-core-melt cleanup is a consideration. NUREG/CR-2800[64] estimates the ORE associated with cleanup to be about 1800 man-rem after a primary coolant spill and about 20,000 man-rem after a core-melt accident. The "typical" frequency of feed-and-bleed events is simply the

"typical" core-melt frequency (1.8×10^{-5}/RY) divided by the feed-and-bleed failure probability (0.20). The actuarial figures are:

Averted Feed-and-Bleed Cleanup ORE/plant	3.6 man-rem
Averted Core-melt Cleanup ORE/plant	7.9 man-rem
Total:	11.5 man-rem

The total averted ORE for all plants is 240 man-rem. Thus, the averted ORE is not dominant, but is still a significant fraction of the averted public risk.

(3) The proposed fix reduces core-melt frequency and the frequency of feed-and-bleed events and therefore averts cleanup costs and replacement power costs. The cost of a feed-and-bleed usage is dominated by roughly six months of replacement power while the cleanup is in progress. If the average frequency of such events is $1.7 \times 10^{-5}/0.20$ or 8.5×10^{-5}/RY and the average remaining lifetime is 23 operational years at 75% utilization, and making the usual assumptions of a 5% annual discount rate and a replacement power cost of $300,000/day, the actuarial savings for feed-and-bleed cleanup works out to be $55,000. Similarly, the actuarial savings of averted core-melt cleanup (which is assumed to cost $1 billion if it happens) are about $200,000. The actuarial savings from replacement power after a core-melt up to the end of the plant life are about $260,000. (This last figure represents the lost capital investment in the plant.) Obviously, these savings would more than offset the cost of the fix if they were included.

(4) The analysis of the first negative scenario, the feedwater line break, assumed that non-isolation of the ruptured line would cause one AFW train to fail. A special situation can arise for plants with a limited AFW water supply (e.g. saltwater plants). In such a case, the continued loss of clean water out of the feedwater line break can in theory cause failure of the second AFW train by exhausting the water supply, provided that the loss is not terminated either by the operator or by protective trips (for runout protection) on the first AFW train. In such a case, the scenario's negative contribution (typical) to the averted core-melt frequency of the proposed fix rises from (-1.8×10^{-8}) to (-1.8×10^{-6}). The net change in core-melt frequency would then drop from 1.7×10^{-5} to 1.6×10^{-5}, which would not change the conclusion.

CONCLUSION

Based upon the figures above, particularly the core-melt frequencies, this issue was placed in the high priority category. A regulatory analysis of the AFW automatic isolation feature showed that, for the postulated removal of the AFW automatic isolation feature in the plants analyzed, (a) the reduction in core damage frequency (CDF) would be in the order of 10^{-7} core damage event/RY, and (b) the risk reduction would be about 40 man-rem/plant. Furthermore, for some plants, it is expected that removal of the automatic isolation of the AFW system would result in an increase in risk. This risk increase is particularly applicable to plants with no flow restrictors in the AFW pump discharge lines. The regulatory analysis was published as NUREG-1332[1133] in September 1988.

Based on the regulatory analysis and its supporting documentation, the staff concluded that removal of the AFW automatic isolation feature will neither result in a substantial safety improvement nor will it be cost-effective. Hence, Alternative Resolution No. 1 - "No Action," as recommended in NUREG-1332,[1133] was adopted as the appropriate resolution of this issue in accordance with the Backfit Rule, 10 CFR 50.109(a)(3). Consistent with the SRP,[11] the "No Action" alternative does not preclude a licensee from proposing to the NRC staff the removal of the AFW automatic isolation feature, based on plant-specific considerations. Thus, this item was RESOLVED and no new requirements were established.[1134]

ITEM 125.II.8: REASSESS CRITERIA FOR FEED-AND BLEED INITIATION

DESCRIPTION

Historical Background

During the course of the investigation of this event,[940] it was discovered that the Davis-Besse emergency procedures (EOPs) criteria for initiation of feed-and-bleed cooling were inadequate. The procedures directed the plant operators to initiate feed-and-bleed either if steam generator levels were below 8 inches on the startup range or if the steam generator secondary pressures were less than 960 psig and decreasing. The difficulties with these criteria were: (1) the control room instrumentation was inadequate for the operators to determine that levels were below 8 inches, and (2) there is calculational evidence that steam generator secondary pressures are unlikely to fall below 960 psig before the opportunity for successful feed-and-bleed cooling is past.[1002] Licensees have been supplied with feed-and-bleed procedures by NSSS vendors.

Safety Significance

Feed-and-bleed capabilities are not currently required by the NRC although the techniques, benefits, and costs are being evaluated in the resolution of USI A-45. Basically, feed-and-bleed cooling is a method of last resort which can avert core damage if main and auxiliary feedwater are lost and other methods of decay heat removal are unavailable. PRAs give considerable credit for feed-and-bleed cooling. A failure rate of one or two percent is a typical assumption. However, the Davis-Besse event chronology leaves an impression that this failure probability may be overly optimistic.

Possible Solution

The Davis-Besse EOPs have been changed; there is now a single criterion for initiating feed-and-bleed which states that feed-and-bleed will be initiated if the primary coolant hot leg temperature rises above 610°F. This parameter is much easier to monitor with existing control room instrumentation and therefore the new criterion is much clearer and unambiguous. The purpose of this proposed generic action is to confirm that all of the remaining B&W plants are using the new criterion rather than the two old criteria.[1002]

CONCLUSION

The safety concern and possible solution of this issue are covered in Issue 122.2, "Initiating Feed-and-Bleed." Issue 122.2 is one of the short-term Davis-Besse issues and is somewhat more general in that it is also concerned with the reluctance of the operators to initiate feed-and-bleed (because of the economic consequences) in addition to being concerned with inadequacy of the criteria. (See References 885, 887, and 940). The two are related; less ambiguity in the written procedures implies less opportunity for reluctance to affect operator actions. Thus, this issue was DROPPED as a new and separate issue.

ITEM 125.II.9: ENHANCED FEED-AND-BLEED CAPABILITY

DESCRIPTION

Historical Background

This particular issue arose because of the very limited capability of the Davis-Besse plant to remove decay heat using feed-and-bleed techniques.[940] The Davis-Besse plant had a relatively low capacity PORV on the pressurizer and thus limited "bleed" capability. In addition, the HPI pumps (a part of the ECCS) did not develop sufficient discharge pressure to provide injection at operating pressure. To supply coolant at elevated pressure, the plant operators would have to "piggyback" the makeup pumps on the HPI discharge, a complex procedure which will supply only rather limited flow. Thus, the "feed" capability was also limited. The issue is divided into two parts: Part A deals with pressure relief capacity (i.e., enhanced "bleed" capability), and Part B deals with makeup capacity and pressure (i.e., enhanced "feed" capability).

Safety Significance

Feed-and-bleed cooling is normally considered a method of last resort which can avert core damage if main and auxiliary feedwater are lost and not recovered. Nevertheless, main and auxiliary feedwater did both fail (but were recovered) at Davis-Besse and so this need for feed-and-bleed, although remote, is a possibility.

Feed-and-bleed cooling has the advantage of being a redundant and diverse method of core cooling. Its disadvantage (in addition to the economic consequences of releasing primary coolant to the containment) is that the plants were not designed for this mode of core cooling and thus their capabilities are uncertain.

An upgrading of the feed-and-bleed capability would benefit the viability of feed and bleed cooling in several ways: (1) the probability of failure due to component failure would be reduced. (Feed-and-bleed cooling can fail due to a single failure at most plants); (2) the thermal hydraulic uncertainty would be reduced. (Feed-and-bleed cooling is often only marginally viable. A slight change in the thermal hydraulic initial or dynamic conditions may well prevent adequate core cooling); (3) the "window" or time interval during which feed-and-bleed is viable would be lengthened, giving more time to (and less stress upon) the operating crew; and (4) the procedures for initiating feed-and-bleed would be simpler, thus reducing the probability of operator error.

Possible Solutions

The possible solutions for this issue are implicit in the definitions of the two parts: (1) increased pressure relief capacity and (2) increased makeup capacity and pressure. Increased relief capacity could be accomplished by installing larger PORVs, installing more PORVs, or installing a special valve intended for bleed operations. Increased makeup capacity would involve upgrading or replacing the pumps (and their motors) with ones of higher discharge pressure.

PRIORITY DETERMINATION

Frequency Estimate

To estimate changes in core-melt frequency due to the upgrades in pressure relief and makeup capacities, it is first necessary to calculate the change in failure probability of feed-and-bleed cooling. In the past, the usual assumptions have been either that the feed-and-bleed failure probability was dominated by the human failure mode (in NRC-generated PRAs) or that it was governed only by a few hardware failure probabilities (in industry-generated PRAs). Obviously, there is an inconsistency. Moreover, the issue to be addressed here affects both hardware and human failure rates. It is necessary to introduce a (somewhat) more sophisticated treatment of the problem. To do this, we will define four classes of plants.

Class 1: In this class, the plant's HPI pumps develop sufficient discharge pressure to lift the pressurizer safety valves. For such plants, feed-and-bleed cooling does not need the PORVs. Moreover, the HPI pumps are capable of raising the coolant level at any time right up to the point of core uncovery. There is no time interval "window" phenomenon.

Class 2: In this class, the plant's HPI pumps and/or charging pumps can force sufficient coolant in at operating pressure, but cannot lift the safety valves. Here, both PORVs must open for feed-and-bleed cooling to work. In addition, the viability of feed-and-bleed techniques is limited in time. Once the steam generators dry out, primary system pressure rises as the primary coolant heats up and expands. The PORVs will open and help keep pressure down, but eventually the pressure will rise up to the safety valve setpoint, by which time the HPI can no longer force coolant into the primary system. Thus, there is a definite "window" of time, pressure, and temperature during which feed-and-bleed cooling will work.

Class 3: In this class, the HPI pumps and/or charging pumps cannot force sufficient coolant into the primary system at operating pressure. Such plants must open the PORVs and reduce pressure to below normal in order to force sufficient coolant in. Of course, the timing is still more critical for such plants. Once the steam generators dry out, the PORV capacity will soon be overcome by primary coolant expansion and heating.

Class 4: This class is similar to Class 3 except that the PORV or PORVs are small. Such plants cannot sufficiently depressurize using PORVs after the steam generators dry out, but instead must open the PORVs and depressurize while the steam generators are still removing decay heat. In some cases, calculations have shown that the PORVs must be opened within 5 to 10 minutes after the beginning of the transient for core cooling to be successful.

It must be emphasized that real plants may not be easily classified into four neat classes. Nevertheless, these four classes will enable the benefits of enhanced feed-and-bleed to be scoped out. The benefit of enhanced pressure relief capacity can be seen by comparing Class 4 with Class 3 and the benefit of enhanced makeup by comparing Classes 2, 3 and 4 with Class 1.

Given the four classes of plants, it is now necessary to discuss the sources of failure for feed-and-bleed. These may be grouped into equipment, thermal-hydraulic, and human failure probabilities.

For feed-and-bleed to work, there must be both feed and bleed capabilities. Thus, a source of coolant at sufficient flow and pressure is necessary. This can be supplied either by the "charging" or "makeup" system (if of sufficient flow capacity) or by the HPI system (if of sufficient discharge pressure). In either case, the supply will generally be from a two-train system. Such systems generally have a failure probability on the order of 1%.

Class 1 plants will discharge through the safety valves which have a failure probability of essentially zero for our purposes. The other three classes must use (usually two) PORVs for coolant discharge. Each PORV has a probability of failure to open of about 1%.[54] When used for feed-and-bleed, these valves are not redundant; both must open.

Thermal-hydraulic effects are reasonably straightforward. For Class 1 plants, the thermal-hydraulic failure probability is essentially zero, since the high head HPI pumps will raise coolant level at any time. For Class 2 and Class 3, we will define two time intervals. The first is T1, which runs from the beginning of the transient up to the point of steam generator dryout. The second is T2, which starts at steam generator dryout and ends at the point of no return, when feed-and-bleed will no longer work. During interval T1, the initial conditions for feed-and-bleed onset are reasonably stable and there is high confidence that feed-and-bleed will work as planned. Thus, the probability of failure due to thermal-hydraulic effects is assumed to be zero during T1. During the second interval T2, the dynamic behavior of the reactor coolant system is much more complicated. In addition, the course of the transient may be significantly affected by a number of factors such as reactor coolant pump operations, PORV cycling, pressurizer sprays, etc. We estimate, based primarily on judgment, that the probability of failure is 50% during this interval.

For Class 4 plants, the point of no return comes well before steam generator dryout. Thus, it will be assumed that the probability of failure due to thermal-hydraulic effects is essentially zero for the first 10 minutes and unity thereafter.

Finally, we must account for human error. This will be divided into three parts:

(1) <u>Simple Procedural Error</u>: Assuming a decision has been made to go ahead with feed-and-bleed, and assuming also that all equipment is operable, there is still a finite probability that the operator will make a mistake in initiating, monitoring, and controlling the process. This failure probability is lowest for Class 1 plants since the operator need only initiate HPI and watch. We will assume 1% failure probability for this class. For Class 2, the initiation and control of feed-and-bleed are more complicated and we will assume 5% for interval T1. For Class 2 interval T2 and

for Classes 3 and 4, the operator must depressurize first and then feed, being careful to keep pressure low enough to get adequate injection flow but high enough to avoid bulk boiling in the core (if possible). For this situation, we will assume a 10% failure rate.

(2) Time Stress: For this, we will use Swain's screening model.[339] The Class 2 and Class 3 interval T1 ends roughly 25 minutes into the transient, for which the screening model estimates a stress failure rate of about 3%. For the case of Class 4, where the point of no return is 10 minutes after the start of the transient, the screening model predicts a 50% failure probability. All the other classes and intervals are well over half an hour and the time stress failure rate is essentially zero.

(3) Simple Reluctance: The use of feed-and-bleed will release primary coolant to the containment atmosphere, contaminating the containment and necessitating a long expensive shutdown for purposes of cleanup. Moreover, feed-and-bleed techniques cause a small LOCA and thus have safety implications. Quite naturally, the plant operators will delay the use of feed-and-bleed as long as possible in the hope of recovering either main or auxiliary feedwater. Thus, there is a finite probability that initiation of feed-and-bleed will be delayed into interval T2 (for Classes 2 and 3) or even past the point of no return. Once again, it is necessary to use judgment. We will assume a 5% probability that the operators will wait until after the point of no return. For Classes 1 and 4, this translates directly into a 5% failure probability. For Classes 2 and 3, we will further assume that there is a 5% chance that feed-and-bleed will be started before the point of no return but after the point of steam generator dryout. This can perhaps best be understood in terms of success probabilities: there is a 90% chance of initiation during interval T1, a 5% chance of initiation during interval T2, and a 5% chance of either no initiation or initiation after interval T2.

For feed-and-bleed to succeed, all the potential pitfalls discussed above must be successfully overcome. Thus, the probability of successful feed-and-bleed is obtained by multiplying the success probabilities (not the failure probabilities) of the various contributors listed above. This is summarized in Table 3.125-2.

For Classes 1 and 4, the failure probability is calculated by first multiplying the equipment, thermal-hydraulic, and operator success probabilities together to obtain a net success probability. This success probability is then subtracted from unity to get a failure probability.

Classes 2 and 3 are more complicated. Within each time interval, the various success probabilities are multiplied together to get a net success probability for the interval. The interval success probabilities are then subtracted from unity to get an interval failure probability (i.e., the probability of no feed-and-bleed during that interval). Both intervals must fail to feed and bleed for feed-and-bleed to not take place at all. Therefore, the failure probability for the plant class is the product of the two interval failure probabilities.

With feed-and-bleed failure probabilities available, the next step is to calculate the changes in core-melt frequencies from these numbers. This is relatively

Table 3.125-2

Class	1	2		3		4
Interval		T1	T2	T1	T2	
Success Probabilities:						
HPI	0.99	0.99	0.99	0.99	0.99	0.99
PORV	---	0.99	0.99	0.99	0.99	0.99
PORV	---	0.99	0.99	0.99	0 99	0.99
Thermal-Hydraulic	1.00	1.00	0.50	1.00	0.50	1.00
Operator:						
Procedural	0.99	0.95	0.90	0.90	0.90	0.90
Time Stress	1.00	0.97	1.00	0.97	1.00	0.50
Reluctance	0.95	0.90	0.05	0.90	0.05	0.95
Interval Success Probability	0.9311	0.8047	0.0218	0.7624	0.0218	0.4148
Interval Failure Probability	0.0689	0.1953	0.9782	0.2376	0.9782	0.5852
Class Failure Probability	0.0689	0.1910		0.2324		0.5852

straightforward in that the dominant sequence is almost always a transient involving a non-recoverable loss of main feedwater coupled with a failure of the AFW system and (of course) a failure to cool the core by means of feed-and-bleed techniques.

For the initiating event frequency (non-recoverable loss of main feedwater), we will use 0.64 event/RY, based upon the Oconee PRA done by Duke Power Co.[889] This figure is based upon fault tree analysis and should be reasonably representative of most main feedwater system designs.

For a three-train AFW system, a "typical" unavailability is 1.8×10^{-5}/demand.[894] The analogous figure for a two-train system is significantly higher. However, an existing program is attempting to upgrade all AFW systems to a point where the maximum unavailability would be 10^{-4}/demand.[947] Thus, we will consider 1.8×10^{-5} to be an average unavailability and 10^{-4} to be the maximum.

With the figures in hand, core-melt frequencies (F) can be estimated by taking the product of the transient frequency, the AFW unavailability, and the change in the feed-and-bleed failure probability.

From Class	To Class	Change in Core-Melt Frequency* Typical	Maximum	Reason
2	1	1.4×10^{-6}	7.8×10^{-6}	Enhanced makeup capacity
3	1	1.9×10^{-6}	1.1×10^{-5}	Enhanced makeup capacity
4	3	4.1×10^{-6}	2.3×10^{-5}	Enhanced relief capacity
4	1	6.0×10^{-6}	3.3×10^{-5}	Enhanced makeup and relief capacity

*in units of core-melt/RY

Consequence Estimate

The accident sequence under consideration here involves a core-melt with no large breaks initially in the reactor coolant pressure boundary. The reactor is likely to be at high pressure (until the core melts through the lower vessel head) with a steady discharge of steam and gases through the PORV(s). These are conditions likely to produce significant hydrogen generation and combustion. The Zion and Indian Point PRA studies used a 3% probability of containment failure due to hydrogen burn (the "gamma" failure). We will follow this example and use 3%, bearing in mind that specific containment designs may differ significantly from this figure.

In addition, the containment can fail to isolate (the "beta" failure). Here, the Oconee PRA[889] figure of 0.0053 will be used. If the containment does not fail by isolation failure or hydrogen burn, it will be assumed to fail by base mat melt-through (the "epsilon" failure).

Using the usual prioritization assumptions of a central midwest plains meteorology, a uniform population density of 340 persons per square mile, a 50-mile radius, and no ingestion pathways, the consequences are:

Failure Mode	Percent Probability	Release Category	Consequences (man-rem)
gamma	3.0%	PWR-2	4.8×10^6
beta	0.5%	PWR-5	1.0×10^6
epsilon	96.5%	PWR-7	2.3×10^3

The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem. These figures should cover all PWRs with large dry containments. However, they do not apply to ice condenser containments. There is no modern PRA currently available for such a plant. However, because of the low free volume in such a containment, failure due to overpressure is more likely and the average consequences may be significantly greater.

Cost Estimate

The core-melt figures for this issue are such that cost considerations will not affect the priority. Consequently, a quantitative cost analysis has not been attempted. However, it should be noted that these are not inexpensive fixes. A new or upgraded high pressure pump is likely to cost between \$2M and \$5M per train installed. Replacement PORVs or an additional, dedicated depressurization valve will not be as expensive, but will probably require replacement discharge piping with stronger bracing. The quench tank might also require extensive modification.

Value/Impact Assessment

To make the value/impact assessment, it is necessary to estimate the number of plants in each of the four classes. The first statement to be made is that all B&W plants except Davis-Besse have injection pumps capable of lifting the pressurizer safety valves. Thus, these plants are already in Class 1 and are outside the scope of this issue. This leaves 71 PWR plants. The earliest implementation of fixes for this issue is not likely to be before the spring refueling outages in 1988, at which time these plants will have a collective remaining lifetime of about 2240 RY. At a 75% utilization figure, this is about 23.7 years of operational life per plant. It is not clear how these 71 plants are distributed among Classes 2, 3 and 4. A plant-by-plant investigation is beyond the scope of a prioritization. Therefore, it will be assumed that roughly one-third fall in each class: 24 in Class 2, 24 in Class 3, and 23 in Class 4. With this data, priority parameters can be estimated.

	Part (a), Enhanced Relief	Part (b), Enhanced Makeup		
Plant Class	4-3	2-1	3-1	4-1
Number of Plants	23	24	24	23
ΔF (average)	4.1×10^{-6}	1.4×10^{-6}	1.9×10^{-6}	6.0×10^{-6}
ΔF (max)	2.3×10^{-5}	7.8×10^{-6}	1.1×10^{-5}	3.3×10^{-5}
Core-Melt/RY (max)	2.3×10^{-5}		3.3×10^{-5}	
Man-rem/reactor (max)	80		120	
Core-Melt/year (Total, all plants)	9.4×10^{-5}		2.2×10^{-4}	
Man-rem (Total, all plants)	330		770	

Other Considerations

(1) Upgrading the makeup capability would involve work on pumps which are located outside of containment. This should not result in a significant amount of ORE. However, upgrading the relief capacity involves work adjacent to the pressurizer which would have implications for occupational exposure. There is no readily available data upon which a direct estimate of this exposure can be based. However, it should be noted that pressurizer inservice inspection involves roughly 20 man-rem and pressurizer

spray valve repair involves roughly 10 man-rem. Thus, because the average (not maximum) plant would avert a public risk of about 15 man-rem, the ORE involved in the fix may well be equal to or greater than the public exposure averted.

(2) In addition to ORE associated with the fix, there is averted ORE associated with cleanup of a core-melt. For prioritization purposes, core-melt cleanup exposure is assumed to be 20,000 man-rem. Using this and the core-melt frequencies calculated previously, the actuarial values (total, all plants) of averted core-melt cleanup ORE are about 45 man-rem for Part (a) and 100 man-rem for Part (b). On a per-plant basis, this is 2 man-rem/plant for both Parts (a) and (b). Thus, this is not a significant consideration.

(3) There are also averted costs associated with this issue. There are no averted precursor events that involve major cleanup, but there are averted cleanup costs associated with the reduction in core-melt frequency. In addition, averted core-melt implies averted replacement power costs for the remaining life of the plant. (Because the plant was built for the purpose of avoiding replacement power costs, this latter item represents the depreciated capital loss of the plant) Using the maximum core-melt frequencies above, a 31.5 calendar-year average remaining plant life, and the usual prioritization assumptions of $1 billion for core-melt cleanup, $300,000 per day for replacement power, and a discount rate of 5%, the actuarial cost credits are:

	Part (a)	Part (b)
Core-melt Cleanup	$270,000	$390,000
Averted Replacement Power Costs	$350,000	$510,000
Total:	$620,000	$900,000

This is probably not sufficient to offset more than a fraction of the cost of the proposed figures.

(4) The estimates of feed-and-bleed failure probability are based upon a time window assumption. That is, after continuing decay heat production in the reactor core has caused primary system pressure to rise to a certain point, the HPI pumps can no longer force coolant into the primary system. In addition, the PORVs are then venting at capacity and thus the primary system cannot be depressurized. Therefore, feed-and-bleed is assumed to fail if initiated after such conditions are reached.

However, a second opportunity for successful feed-and-bleed may exist. This would occur after the primary coolant boils away to the point where the core is starting to uncover. The steaming rate then begins to diminish and the PORVs may be able to depressurize the primary system to the point where the HPI pumps can reflood the core.

Of course, this depressurization is only possible because the decay heat is causing the uncovered fuel's temperature to rise instead of going into steam production. The pressure may not drop fast enough for core melt to be averted. Also, if the uncovered fuel slumps or crumbles and falls into the remaining liquid coolant, pressure will rise again. It is beyond the scope of a prioritization to address this (theoretical) second window possibility. However, any subsequent value/impact analyses should address the possibility of a second window.

(5) The analysis assumes a 1% failure probability for the PORV(s). Some plants have operated for extensive periods with the PORV block valves closed and electrically disabled. Restoration of power to the block valve operators, and subsequent opening of the block valves and PORVs to permit feed-and-bleed cooling, would take a significant amount of time as well as opening new possibilities for equipment malfunction and operator error. Thus, such plants might have feed-and-bleed failure probabilities significantly greater than those calculated in the analysis above.

CONCLUSION

Based upon the above analysis, particularly the maximum core-melt frequencies, this issue would normally be placed in the high priority category. However, feed-and-bleed techniques are being evaluated[738] and will be considered as one option in the resolution of USI A-45.[953] Therefore, this issue was DROPPED as a separate issue.

ITEM 125.II.10: HIERARCHY OF IMPROMPTU OPERATOR ACTIONS

DESCRIPTION

Historical Background

During the event, the operators did not initiate feed-and-bleed cooling immediately upon reaching plant conditions where feed-and-bleed operations were required by the emergency procedures.[940] The feed-and-bleed method of cooling was delayed because of the operators' belief that recovery of feedwater was imminent and their reluctance to release reactor coolant to the containment structure. Even though feedwater flow was recovered before serious damage resulted, the event highlighted the need for establishing a hierarchy of actions in the procedures and/or training which would focus impromptu actions during an event to assure that decisions will be in the direction of safety, and not based on potential plant operational difficulties and financial impacts.

Safety Significance

Delays in implementing emergency operating procedures (EOPs) in a timely manner could defeat the design safety function of equipment and increase the severity of a transient or accident.

Possible Solution

Issue HF4.4 is to provide assurance that plant procedures are adequate and can be used effectively; the objective is to provide procedures that will guide the operators in maintaining the plant in a safe state under all operating conditions, including the ability to control upset conditions without first having to diagnose the specific initiating event. This objective is to be met by: (1) developing guidelines for preparing, and criteria for evaluating, EOPs, normal operating procedures, and other procedures that affect plant safety; and (2) upgrading procedures, training the operators in their use, and implementing the upgraded procedures.

In accordance with Appendix A of NUREG-0985, Revision 2,[651] comparative studies have been completed which examined the impact on operator performance in making the transition from procedure to procedure, using either event-based or function-oriented EOPs. The results of these studies are being incorporated into a larger, ongoing project to develop guidance for achieving successful transitions with nuclear power plant operating procedures. DHFT concluded that, while the procedural guidance package may develop the correct guidance to place the reactor in a safe state, it may not prevent reluctance on the part of supervision or an operator to take action which will invariably result in a financial penalty. The TMI Action Plan Item I.B.1.3 (Loss of Safety Function) resolution to use existing enforcement options (citations, fines, and shutdowns) provides a deterrent to such actions, including willful violations, that could effect the health and safety of the public (10 CFR 2, Appendix C).[197] The Commission noted[234] that, while the procedures for enforcement actions may not ensure compliance, civil penalties and possibly criminal prosecution for willful violations are strong incentives to comply. NRC policy is that noncompliance should be more expensive than compliance. In cases involving individual operators licensed under 10 CFR Part 55, the Commission policy statement[234] states that generally licensees are held responsible for the acts of their employees. Accordingly, the NRC policy should not be construed as excusing personnel errors. Thus, enforcement actions involving individuals, including licensed operators, will be determined on a case-by-case basis. The NRC policy is directed toward encouraging licensee initiatives for self-improvements and identification and correction of such problems.

CONCLUSION

The concern raised relative to reluctance of the licensee (or plant operators) to proceed with appropriate actions to place the plant in a safe state of operation, based on potential plant operational difficulties and financial impacts, is addressed by existing NRC policies.[197,234] Based on the above discussion, the issue involving development of the hierarchy of impromptu operator actions is to be addressed in Issue HF4.4. Therefore, Issue 125.II.10 was DROPPED as a separate issue.

ITEM 125.II.11: RECOVERY OF MAIN FEEDWATER AS ALTERNATIVE TO AUXILIARY FEEDWATER

DESCRIPTION

Historical Background

The issue deals with alternate means of recovering feedwater, should the AFW systems fail, and applies to all PWR plants.[940]

Safety Significance

Failure to provide feedwater makeup to the steam generators will cause them to boil dry in approximately 30 minutes or less. (This time varies for plant type and power level). As steam generator water level decreases, heat removal rate is impaired and the temperature of the primary side increases. This leads to an imminent need to initiate feed-and-bleed cooling or find an alternate method of steam generator makeup. If no means of cooling is provided, the resulting loss of primary coolant inventory out of the pressurizer relief and safety valves will lead to core uncovery and meltdown.

Possible Solution

In the resolution of Issue 124, "Auxiliary Feedwater System Reliability," the staff evaluated potential alternate recovery methods for both main and auxiliary feedwater systems for those plants (7 plants) with two-train AFW systems. The staff effort was predicated on the lower AFW reliability associated with only two-train AFW systems as opposed to the majority of plants that have three-train AFW systems. The staff reviews and evaluations consisted of plant-specific reviews and on-site audits. Contingent upon implementation of the staff recommendations proposed as the resolution of Issue 124, Issue 125.II.11 should be dropped as a new and separate issue for these plants.

As a more generic approach,[1083] previous staff reviews of emergency procedure guidelines (EPGs) recognized that alternate methods to provide flow to the steam generator in the event of a loss of both main feedwater and AFW were desirable. Therefore, the EPGs for the W and CE plants were revised to include instruction for an alternate means of feedwater recovery. A similar change was also required for inclusion in the B&W EPGs by Generic Letter No. 83-31.[1085]

CONCLUSION

On the basis of the above, this issue was DROPPED as a separate generic issue.

ITEM 125.II.12: ADEQUACY OF TRAINING REGARDING PORV OPERATION

DESCRIPTION

Historical Background

This issue affects all operating PWRs with PORVs in the primary coolant loop and calls for an assessment of the adequacy of training regarding PORV operations.[940] The issue stems from Findings 8 and 14 of the NRC investigation of the Davis-Besse event[886] of June 9, 1985 in which the NRC staff noted that the post-TMI improvements that focused on EOPs and training played a crucial role in mitigating the event. Following actuation of the PORV during the event, the operator observed that the PORV open/close indicator showed that the PORV had closed. In fact, the PORV had not completely closed and, as a result, the reactor pressure decreased at a rapid rate for about 30 seconds. The operator however did not verify closure of the PORV by looking at the acoustical monitor installed after the TMI accident; instead, he looked at the indicated pressure level which appeared steady. As a precautionary measure, the operator closed the PORV block valve. Fortunately, when the block valve was subsequently opened to assure PORV availability, the PORV had closed during the time the block valve was closed. Had the operator looked at the acoustical monitor, the need to close the block valve may have been factually confirmed and may have precluded the need for relying on the precautionary action taken. However, it should be noted that the operators have not generally placed high reliance on the acoustical monitors because of PORV leakage problems.

Safety Significance

Assessments of the adequacy of training and hands-on experience, referred to as performance-based training or Systems Approach to Training (SAT), is considered essential for providing assurance that nuclear power plants are operated in a safe state under all operating conditions. The adequacy of training regarding the PORV operation is part of the assessments of the performance-based training evaluations described in Issue 125.I.7.b, "Realistic Hands-on Training."

Possible Solution

A possible solution to this issue is to include an assessment of the adequacy of training regarding PORV operations in the job catalog of necessary tasks and functions required to safely operate and control nuclear power plant operations.

PRIORITY DETERMINATION

Frequency Estimate

PORV Challenge Frequency: The PORV challenge frequency was determined to be approximately 1/RY in Issue 70, "PORV and Block Valve Reliability."

PORV/Block Valve Failure Frequency: The frequency of failure of the PORV to close, given that it has opened, is estimated to be 0.01/demand (See Issue 70). The frequency of failure of the block valve to function is estimated to be 0.003/demand (See Issue 70).

Operator Error Frequency: Based on the information in Issue 70, the human error probability (HEP) to close the PORV after the TMI Action Plan[48] improvements and increased emphasis on operator training is estimated to be 0.05.

PORV-SBLOCA Frequency: The estimated base-case PORV/block-valve SBLOCA frequency (5.3×10^{-4}/RY) is the product of the PORV challenge frequency (1.0), the probability that the PORV sticks open (0.01), and the probability that the operator will not close the PORV or the block valve fails to close (0.05 + 0.003).

To assess the potential improvement in HEP for PORV operations that may result from adequate hands-on training in upgraded simulators, a 30% reduction in HEP is assumed. (See Issue I.A.4.2, "Long-Term Training Simulator Upgrade.") Adjusting the above HEP = 0.05 to account for the potential reduction in HEP, the adjusted HEP = (0.7)(0.05) = 0.035. The resulting potential reduction in PORV-SBLOCA frequency derived by requiring the PORV training in the job catalog (Issue HF3.1) is therefore estimated to be $[(5.3 \times 10^{-4})/\text{RY} - (1.0)(0.01)(0.035 + 0.003] = 2.5 \times 10^{-4}$/RY. Given the visibility of PORV training since the TMI-2 accident, the above 30% reduction in HEP may over-estimate the potential HEP benefit. However, the assumed 30% reduction is expected to bound the safety significance of this issue.

Consequence Estimate

Ratioing the above reduction in PORV-SBLOCA frequency (2.5×10^{-4}/RY) to the PORV-SBLOCA frequency from Issue 70 (1.05×10^{-3}/RY) and multiplying by the core-melt frequency from Issue 70 (4.2×10^{-6}/RY) yields the potential reduction in core-melt frequency for this issue of $(0.24)(4.2 \times 10^{-4}/RY) = 10^{-6}/RY$. The public risk reduction is therefore (0.24)(31 man-rem/reactor) = 7.4 man-rem/reactor (See Issue 70).

CONCLUSION

Issue HF3.1 evaluated the task selection process for training program content based on the relative importance of operator tasks and requirements. Tasks involving the use of PORVs for both feed-and-bleed cooling and for identification of potential LOCAs are included in the generic INPO task analysis listings for PWRs and in NUREG-1122,[974] Item EK3.03, "Actions Contained in EOP for PZR Vapor Space Accident/LOCA." This event has one of the highest importance ratings (4.6 of 5.0) for PWRs and is included in both training and NRC exams. The high frequency of PORV challenges is to be addressed in Issue HF3.1. Therefore, Issue 125.II.12 was DROPPED as a separate issue.

ITEM 125.II.13: OPERATOR JOB AIDS

DESCRIPTION

In a DHFT memorandum[900] on September 19, 1985, it was suggested that an assessment be made of the availability of appropriate job aids to obviate operators having to rely heavily on memory in emergency or "crisis" conditions. In a DSRO memorandum[1072] of June 12, 1986, it was requested that DHFT evaluate this issue for inclusion in the Human Factors Program Plan (HFPP) or perform an analysis of the issue to determine its priority.

Safety Significance

In the Davis-Besse occurrence, two operator-related problems were encountered which were involved in the sequence of events that transpired. The first problem occurred when the secondary side operator, anticipating the automatic trip of the Steam Feedwater Rupture Control system (SFRCS), which would start the AFW system, elected to perform a manual trip. However, the operator selected and actuated the wrong pair of pushbuttons from a set of five pairs and, instead of initiating an SFRCS trip for low water in the steam generators, obtained a trip for low steam pressure. This action isolated both steam generators from the AFW system by closing the isolation valves. At about the same time, both AFW pump turbines tripped on overspeed. Recovery of AFW pumps due to the overspeed trips could not be accomplished by actions in the control room.

The second problem was encountered when two equipment operators were unable to reset the AFW pump turbine trip throttle valves and promptly restore feedwater delivery to the steam generators. Both equipment operators, while having a reasonable amount of nuclear power plant experience, had never previously performed the task of resetting, latching and opening the turbine trip throttle valves, particularly under full operating pressure. One equipment operator had successfully reset and latched the No.2 trip-throttle valve but, due to the high friction caused by large differential pressure across the valve gate, removed only the mechanical slack in the valve mechanism and did not open the valve. The other operator had latched but did not reset the No. 1 trip-throttle valve and had partially opened the valve, but was fearful of applying more torque to open the valve further. The turbine, as a result, was operating at 2/3 its normal speed, which did not provide enough discharge pressure to inject water into the steam generator. It was not until the assistant shift supervisor came into the pump room that the operators knew that the trip-throttle valves were not opened enough. At about the same time, another, more experienced, equipment operator arrived with a valve wrench; using this tool he successfully opened the No.2 valve then also reset and opened the No. 1 valve.

Possible Solution

It is conceivable that operator aids could have reduced the likelihood of the first operator error and decreased the time required for the equipment operators to open the turbine trip-throttle valves. "Operator aids" is a term which applies to a broad category of items which assist the operators, physically or mentally, in accomplishing their tasks. Operator aids may be markings or codings, tags, tools or devices to physically assist the operator, the layout or arrangement of equipment items, and the equipment design features including provision for human interface. Examples of operator aids which could have assisted the control room and equipment operators include, but should not be limited, to the following:

(a) The markings on the SFRCS pushbuttons could have described the results of actuation rather than the trip which they generate. For example, instead of low steam pressure trip, the inscription might read SG feedwater isolation; and instead of low water level trip, they might be labeled AF initiation.

(b) Since a valve wrench is required to open the trip-throttle valves under pressure, a valve wrench might be permanently stored in the AFW pump rooms for use in emergencies.

(c) Since there existed some confusion about resetting and latching the trip-throttle valves, linkage guidance or instructions could be depicted on the AFW pump room walls to guide the unfamiliar. The mechanical linkage could also have been color-coded or conspicuously marked.

Again, the preceding are only examples of operator aids and are not intended to be an exhaustive list of all such operator aids which could have enhanced the operators actions in the Davis-Besse event. Other generic issues that are related to the safety concern of this issue include: 125.I.7.a, "Recovery of Failed Equipment"; 125.I.7.b, "Realistic Hands on Training"; and 125.II.10, "Hierarchy of Impromptu Operator Actions."

CONCLUSION

There certainly is no dispute that operator job aids can enhance an operator's ability to perform his task. However, any attempt to define what job aids are needed on a generic basis is very difficult. Even more difficult are efforts to quantify the risk reduction which can result from efforts to improve or provide absent job aids. Any attempt at quantification would be very arbitrary and without much justification. Operator job aids is not a solution that stands on its own merit, but is supportive of other human factors elements such as staffing, qualifications, and training. While the availability of operator job aids may enhance an operator's ability to accomplish his task, the absence of job aids only reduces the reliability of human performance and does not necessarily imply operator failure.

The presence or absence of operator job aids becomes a factor which is considered in the job task analysis and upon which training requirements are established. Provisions are included in the INPO-managed training accreditation program to ensure that the feedback from operating events such as the Davis-Besse event are included in utility training programs. In addition, a portion of the operator job aids is to be addressed in the resolution of the man-machine interface Issue HF5.1, "Local Control Stations."

The safety concern of this issue has been addressed by the INPO Training Accreditation Program which was endorsed in March 1985 by the Commission Policy Statement on Training and Qualification of Nuclear Power Plant Personnel.[996] Therefore, this issue was DROPPED from further consideration as a separate issue.

ITEM 125.II.14: REMOTE OPERATION OF EQUIPMENT WHICH MUST NOW BE OPERATED LOCALLY

DESCRIPTION

Historical Background

During the course of the investigation of the event, it was noted that a startup feedwater pump (SUFP), a part of the main feedwater system that would have been very helpful in the mitigation of the transient, had been intentionally disabled because of an NRC concern with high energy line breaks in the area of essential safety equipment and the ability of ECCS equipment to meet single failure criteria. Although the Davis-Besse event specifically involved a SUFP, it is intended that this issue cover all equipment that has been disabled such that it is no longer remotely operable from the control room.

Safety Significance

The significance of purposely disabled equipment lies primarily in timing. Generally, it is possible to restore such equipment to an operable status. However, plant personnel must be dispatched to the equipment to perform local, manual operations such as unlocking and manipulating manual valves, restoring and closing breakers, etc. This can require considerable time and restoration to operability may well come too late to aid in accident mitigation. Moreover, the relatively complex procedures involved, done under emergency conditions, are prone to error. Finally, the nature of the incident may well be such that the disabled equipment is rendered inaccessible.

Possible Solution

The solution proposed[900] is straightforward: "Review each piece of motor-operated equipment originally designed to be operated from the control room or other panel areas which has been disabled physically such that it can only be operated locally to determine whether such disabling truly is in the interest of overall plant safety."

PRIORITY DETERMINATION

Over the years, there have been many instances where equipment has been intentionally disabled. In the case of the Davis-Besse SUFP, the reason was to ensure that the discharge lines, which are not seismically qualified and which also are routed near essential safety equipment, could not rupture and disable this equipment. Other reasons also exist. For example, equipment has in the past been disabled by removal of breakers to permit older ECCS designs to meet the single failure criterion.

This issue is non-specific in the sense that it addresses any of this disabled equipment. Thus, re-enabling of this equipment may affect LOCA sequences, transient-initiated sequences, etc. Because of this very general nature, it is impossible to quantify all aspects explicitly. The approach we will use is to evaluate a SUFP similar to that of Davis-Besse, but (unlike the case of Davis-Besse) capable of providing sufficient flow by itself to permit decay heat removal by means of the steam generators. Because such a pump would help mitigate transient-initiated sequences, which are relatively frequent compared to (for example) LOCA-initiated sequences, this scenario should provide an upper bound to the priority parameters.

Frequency Estimate

The sequence of interest is straightforward. It is initiated by a nonrecoverable loss of main feedwater. If the auxiliary feedwater system fails, the SUFP is not re-enabled in time, and feed-and-bleed techniques fail, core melt will ensue.

For the initiating event frequency (non-recoverable loss of main feedwater), we will use 0.64 event/RY, based upon the Oconee PRA done by Duke Power Co.[889] This figure is based upon fault tree analysis and should be reasonably representative of most main feedwater system designs.

For a three-train AFW system, a "typical" unavailability is 1.8×10^{-5}/demand.[894] The analogous figure for a two-train system is significantly higher. However, an existing program (Issue 124) is considering whether to upgrade all AFW systems to a point where the maximum unavailability would be 10^{-4}/demand. These plants would almost certainly upgrade their SUFPs (if present) to help meet this criterion, which makes this issue moot for these plants; thus, we will use 1.8×10^{-5}/demand.

We will assume a typical value of 0.20 for the failure probability of feed-and-bleed cooling, based upon the calculations presented under Issue 125.II.9, "Enhanced Feed-and-Bleed Capability."

The SUFP non-recovery probability remains to be calculated. According to the Investigation Team's report on the Davis-Besse event,[886] restoration of the

SUFP normally takes 15 to 20 minutes. Nevertheless, the assistant shift supervisor managed to do it in roughly 4 minutes during the June 9, 1985 event. Obviously, not all plant personnel are going to go through the procedure as rapidly as the assistant shift supervisor at Davis-Besse even given the extra motivation of a real event. We will assume that the time needed to restore the SUFP to operability can be described by a normal distribution, centered at 17.5 minutes and with a width such that the assistant shift supervisor's performance of 4 minutes is at the first 95 percentile point.

The time intervals above are measured from the start of the restoration procedure. It is desirable for calculational purposes to measure time from the initiation of the transient. Noting from NUREG-1154[886] that the SUFP was restored at t = 16.38 minutes (measured from the start of the transient) after four minutes of rapid work on the part of the assistant shift supervisor, the significant times are:

$t = 0$,	start of transient
$t = 12.38$ minutes,	start work on SUFP
$t_{95} = 16.38$ minutes,	95 percentile point
$t_0 = 29.88$ minutes,	mean time for restoration

Thus, the probability of the SUFP being restored within the interval from t to (t + dt) is given by:

$$P(t)dt = (\sqrt{2\pi}\,\sigma)^{-1} \exp\{-\tfrac{1}{2}[(t-t_0)/\sigma]^2\}dt$$

where $\sigma = 8.93$ minutes (based on $t_0 - t_{95} = 13.5$ minutes)

If one is willing to wait long enough, the integrated probability of restoration approaches unity. However, there is a point in time after which restoration of the SUFP will no longer save the core. Although it is not clear just when this time is, it is safe to assume that it occurs after steam generator dryout which is typically at least 25 minutes into the transient. The probability of no restoration is given by:

$$P_F(T) = \int_T^{\infty} P(t)\,dt, \text{ where } T \geq 25 \text{ minutes}$$

There is no closed form solution to this integral. However, standard statistical tables readily give an answer of $P_F(T) \leq 0.29$.

One last effect needs to be considered. Consistent with Issue 122.3, "Physical Security System Constraints," an additional 1% probability of the plant personnel being unable to reach the equipment location because of locked doors, etc., must be considered. The core-melt frequency then becomes:

Core-melt/RY $\leq$ (0.64 loss of main feedwater events/RY) x
(1.8×10^{-5} AFW failure probability) x
(0.20 feed-and-bleed failure probability) x
(0.29 + 0.01 SUFP non-restoration probability)

$\leq 6.9 \times 10^{-7}$

Consequence Estimate

The core-melt sequence under consideration here involves a core-melt with no large breaks initially in the reactor coolant pressure boundary. The reactor is likely to be at high pressure (until the core melts through the lower vessel head) with a steady discharge of steam and gases through the PORV(s). These are conditions likely to produce significant hydrogen generation and combustion.

The Zion and Indian Point PRA studies used a 3% probability of containment failure due to hydrogen burn (the "gamma" failure). We will follow this example and use 3%, bearing in mind that specific containment designs may differ significantly from this figure.

In addition, the containment can fail to isolate (the "beta" failure). Here, the Oconee PRA figure of 0.0053 will be used. If the containment does not fail by isolation failure or hydrogen burn, it will be assumed to fail by basemat melt-through (the "epsilon" failure).

Using the usual prioritization assumptions of a central midwest plains meteorology, a uniform population density of 340 persons per square mile, a 50-mile radius, and no ingestion pathways, the consequences are:

Failure Mode	Percent Probability	Release Category	Consequences (man-rem)
gamma	3.0%	PWR-2	4.8×10^6
beta	0.5%	PWR-5	1.0×10^6
epsilon	96.5%	PWR-7	2.3×10^3

The "weighted-average" core-melt will have consequences of 1.5×10^5 man-rem.

The plants to be examined include all operating plants (presently 94). As of the fall of 1987 (the earliest that changes are likely to be made), these plants will have an aggregate remaining license lifetime of 2718 RY. This corresponds to an average lifetime of 29 calendar-years per plant. At a 75% utilization factor, this is 22 operational years per plant.

It is not known how many plants would be affected by this issue. We will assume that at least a few plants will be found and will calculate priority parameters on a per-plant basis. Thus, the estimated risk reduction per plant is $(6.9 \times 10^{-7})(22)(1.5 \times 10^5)$ man-rem or 2.3 man-rem.

Cost Estimate

The fix for this issue, once equipment is identified, is to do a detailed analysis to see if the disabling of the subject equipment is truly in the interest of plant safety. If the analysis indicates that the equipment should not be disabled, the original reason for disabling must still be addressed. (Alternatives to disabling may be necessary to address the original concern.)

The minimum cost would correspond to a case where the equipment is process equipment, which is fully maintained and needs only to have valves opened and breakers re-installed, which would take (we assume) roughly 17.5 minutes of labor. If it also turns out that no other alternatives are necessary, the cost would be dominated by analysis and paperwork. We estimate that probabilistic analyses would require approximately 10 weeks of staff time (NRC and industry combined) per plant, at $100,000/staff-year. In addition, per-plant costs of $13,000 for NRC and $16,000 for the licensee would be incurred for a typical straightforward technical specification change. The minimum cost is then about $50,000/plant.

Value/Impact Assessment

Based on a potential risk reduction of 2.3 man-rem/reactor and a cost of $50,000/reactor, the value/impact score is given by:

$$S = \frac{2.3\ \text{man-rem/reactor}}{\$0.05\text{M/reactor}}$$

$$= 46\ \text{man-rem/\$M}$$

Other Considerations

The aggregate parameters (total man-rem, all reactors, and total core-melt/year, all reactors) are not calculated here. An examination of the scale factors for these parameters readily shows that at least 50 plants must be affected before it is possible for these parameters to be limiting.

In most cases, the fix will not involve work within radiation fields and thus will not involve ORE. The ORE averted due to post-feed-and-bleed-cleanup and post-core-melt cleanup is a minor consideration. The ORE associated with cleanup is estimated to be 1800 man-rem, after a primary coolant spill, and 20,000 man-rem, after a core-melt accident.[64] If the frequency of feed-and-bleed events is 3.46×10^{-6}/RY, the actuarial cleanup ORE averted is only 0.14 man-rem/reactor. Similarly, a core-melt frequency of 6.9×10^{-7}/RY corresponds to an actuarial averted cleanup ORE of only 0.30 man-rem/reactor. If averted ORE were added to the man-rem/reactor and man-rem/$M figures above, no conclusions would change.

The proposed fix would reduce core-melt frequency and the frequency of feed-and-bleed events and therefore would avert cleanup costs and replacement power costs. The cost of a feed-and-bleed usage is dominated by roughly six months of replacement power while the cleanup is in progress. If the average frequency of such events is 3.46×10^{-6}/RY and the average remaining lifetime is 29 calendar-years at 75% utilization, then making the usual assumptions of a 5% annual discount rate and a replacement power cost of $300,000 per day, the actuarial savings for feed-and-bleed cleanup is estimated to be $2,200. Similarly, the actuarial savings of averted core-melt cleanup (which is assumed to cost one billion dollars if it happens) are about $7,900. The actuarial savings from replacement power after a core-melt up to the end of the plant life are about $9,600. (This last figure represents the lost capital investment in the plant.) If these theoretical cost savings were subtracted from the expense of the fix, the value/impact score would rise to 76 man-rem/$M and would not change any conclusions.

Some caution is needed in the use of the numbers calculated above. It must be remembered that these are maximum numbers, calculated for a worst case scenario. It must also be remembered that equipment has often been disabled for good reasons. Re-enabling such equipment will generally have drawbacks as well as benefits and the net effect on plant safety is not necessarily positive.

CONCLUSION

Based upon the figures presented above, this issue was given a LOW priority.

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TASK HF1: STAFFING AND QUALIFICATIONS

This task was developed to assure that the number and capabilities of the staff at nuclear power plants are adequate to provide safe operation. To meet this goal, consideration will be given to: (1) the numbers and functions of the staff needed to safely perform all required plant operations, maintenance, and technical support for each operational mode; (2) the minimum qualifications of plant personnel in terms of education, skill, knowledge, training experience, and fitness for duty; and (3) appropriate limits and conditions for shift work including overtime, shift duration, and shift rotation.

ITEM HF1.1: SHIFT STAFFING

DESCRIPTION

This issue called for a determination of the minimum appropriate shift crew staffing composition. This determination was to be made from developed personnel projection and allocation models and from evaluations of job and task analyses and PRA data. Staffing practices of foreign and domestic utilities were surveyed to evaluate current practices, regulations, and staffing levels considering such variables as plant size, control room arrangement and configuration, and plant layout. The issue consists of two parts: (1) the Staffing Rule and (2) conforming amendments to Regulatory Guide 1.114[995] and SRP[11] Section 13.1.2.

The Staffing Rule which is officially known as "Licensed Operator Staffing at Nuclear Power Units" was published in the Federal Register on July 11, 1983 (48 FR 31611)[994] with an effective date of January 1, 1984; this rule is now included in 10 CFR 50.54. The proposed conforming requirements to Regulatory Guide 1.114[995] and SRP[11] Section 13.1.2 contain no requirements beyond those included in the Staffing Rule. Implementation of these requirements will be verified by resident inspectors. No further verification will be necessary upon issuance of the Regulatory Guide[995] and SRP[11] changes.

CONCLUSION

In pursuing the resolution of this high priority issue, the staff issued Revision 2 to Regulatory Guide 1.114[995] in May 1989. A draft revision to SRP[11] Section 13.1.2 was prepared by RES and forwarded to NRR for publication.[1232] Thus, this issue was RESOLVED and new requirements were established.

ITEM HF1.2: ENGINEERING EXPERTISE ON SHIFT

DESCRIPTION

This issue called for a decision on the need for engineering expertise on shift. This decision was to be based in part on the functions and duties required by using the results of the job/task analysis and evaluating the STA experience. A policy statement on engineering expertise on shift was to be issued and its effectiveness evaluated. This issue was identified in Table 7 of the NRC 1985 Annual Report as Item 1.1 of the HFPP but was made Item HF1.2 in June 1986[990]. The final policy statement was approved by the Commission on September 12, 1985 and was published in the Federal Register on October 28, 1985 (50 FR 43621).[996]

CONCLUSION

This issue has been RESOLVED and no new requirements were established.

ITEM HF1.3: GUIDANCE ON LIMITS AND CONDITIONS OF SHIFT WORK

DESCRIPTION

Experience and research data indicate that shift work and the use of overtime can have an adverse effect upon operator performance. To determine the appropriate limits and conditions for shift work, activities are planned to: (1) determine the effects of varying shift duration using nuclear power plant simulators, and (2) survey and assess the experience of other industries with job requirements similar to the nuclear industry with regard to shift arrangements and rotation. This effort will allow the NRC to establish trade-offs among factors affecting shift work and overall safe performance requirements. The results were to be reported as a NUREG document and a specific research effort was to undertaken if shift rotation and conditions of overtime were found to be serious human factors problems.

CONCLUSION

This issue was resolved with the issuance of Generic Letters 82-12[979] and 82-16[980] and no new requirements were established.

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TASK HF4: PROCEDURES

This task is to provide assurance that plant procedures are adequate and can be used effectively. The objective in to provide procedures which will guide the operators in maintaining the plant in a safe state under all operating conditions, including the ability to control upset conditions without first having to diagnose the specific initiating event. This objective is to be met by: (1) developing guidelines for preparing, and criteria for evaluating, emergency operating procedures (EOPs), normal operating procedures, and other procedures which affect plant safety; and (2) upgrading the procedures, training the operators in their use, and implementing the upgraded procedures. This task is divided into five distinct items; the following is a discussion of these five items.

ITEM HF4.1: INSPECTION PROCEDURE FOR UPGRADED EMERGENCY OPERATING PROCEDURES

DESCRIPTION

Criteria to evaluate and inspect EOPs by the regions have been prepared by NRR and OIE and were published as an OIE Temporary Instruction. Similar criteria and inspection modules will be developed when the guidelines for the upgrading of other procedures are completed.

CONCLUSION

This item has a HIGH priority ranking.

ITEM HF4.2: PROCEDURES GENERATION PACKAGE EFFECTIVENESS EVALUATION

DESCRIPTION

To evaluate the effectiveness of the NRC's long term program for upgrading EOPs, the staff has been auditing the implementation of Procedures Generation Packages (PGPs) at selected plants. The PGP describes a plant's program for adapting the generic technical guidelines to develop the technical content of plant-specific EOPs and applying human factors principles to produce EOPS which are usable by operators. Six audits have been performed and additional audits are planned before an assessment of the program is completed. Based on input from sources including PGP implementation audits, staff PGP reviews, and license examiners, the staff has identified problems that plants are experiencing with implementing their PGPs. to alert the industry to these problems, the staff issued an Information Notice. Progress by the industry in addressing the problems identified in the Notice will be monitored by inspections, additional PGP implementation audits, and through continued dialogue with industry.

This item is related to increasing knowledge, certainty, and understanding of safety issues in order to increase confidence in assessing levels of safety and is, therefore, considered a licensing issue.

CONCLUSION

This Licensing Issue has not been resolved.

ITEM HF4.3: CRITERIA FOR SAFETY-RELATED OPERATOR ACTIONS

DESCRIPTION

A safety evaluation standard will be developed with which to screen licensee proposals to place additional burdens upon operators. Licensees proposing to resolve severe accident issues or other generic safety issues by adding to emergency operating procedures and training, in lieu of a hardware fix, will be expected to utilize the standard to verify that the additional burdens placed upon operators do not overload the operators, and that the additional operator responsibilities are adequately covered in procedures and training. This standard will apply to any licensee proposing to add additional operator responsibilities as part of the resolution of a generic safety issue, but we do not anticipate that it will be applied retroactively to DBAs or existing EOPs. It will not impose requirements upon plant design or operation directly, but may narrow the range of options available to resolve other issues. The likely form is an SRP[11] Section.

CONCLUSION

This item is covered in Item B-17.

ITEM HF4.4: GUIDELINES FOR UPGRADING OTHER PROCEDURES

DESCRIPTION

On the basis of current efforts to evaluate the quality of and the problems associated with existing plant procedures, NRR is evaluating the need to develop technical guidance for the industry to use to upgrade normal operating procedures (OPs) and abnormal operating procedures (AOPs) as the staff has done for EOPs. Future work in this area includes performing a regulatory analysis to determine whether regulatory action for other plant procedures is warranted, and, if so, to develop formal regulatory requirements.

In December 1982, Supplement 1 to NUREG-0737 was issued as Generic Letter 82-33.[376] This document made it a requirement for each plant to submit a Procedures Generation Package (PGP) as a part of the effort to upgrade EOPs. Generic Letter 82-33 also indicated that the NRC would audit upgraded EOPs on a selective basis. In accordance with the Generic Letter, the NRC began auditing upgraded EOPs in 1984. After conducting several audits, the staff issued Information Notice No. 86-64[1210] to advise the industry that there were indications that many utilities were not appropriately developing and implementing upgraded EOPs. Based on the deficiencies identified in the Information Notice, the staff concluded that other utilities might not have appropriately developed and implemented upgraded EOPs in accordance with PGPs. The staff decided to continue with its audit program to further determine the scope and safety significance of the deficiencies identified in the Notice and conduct inspections at all plants to evaluate the implementation of licensee commitments to develop and implement upgraded EOPs.

CONCLUSION

This issue was given a high priority ranking and pursued by the staff. In June 1986, the staff prepared Temporary Instruction (TI) 2515/79, which contained criteria for inspecting how well licensees were complying with their PGP commitments. In April 1987, the staff issued a supplement to its first Information Notice based on evaluations from 6 additional plants. In early 1988, the staff suspended its program to evaluate licensees' compliance with programmatic requirements (i.e., PGPs) and redirected its efforts to focus more on the technical adequacy and useability of the EOPs. Lessons learned by the staff from its inspection program for EOPs were published in NUREG-1358.[1209] TI 2515/92,[1209] "Emergency Operating Procedures Team Inspections," contains guidance for conducting these inspections. Based on the results from this inspection program of 28 plants, NRR will develop a program of inspections for the remaining facilities. Thus, this issue was RESOLVED and no new requirements were established.[1208]

ITEM HF4.5: APPLICATION OF AUTOMATION AND ARTIFICIAL INTELLIGENCE

DESCRIPTION

The level of automation possible within the nuclear industry spans a range of possibilities from the fully manual, with locally operated valves, to the fully automated, employee artificial intelligence. The nuclear industry is basically at the one-switch one-valve end of that range. The reliability of artificial intelligence (AI) for safety-related uses is currently unproven; however, evidence from other industries suggests that there can be significant savings in operating costs as well as an enhancement in safety associated with increased automation of operator actions. Reducing the menial level workload of operators could provide better low-level control and fewer operator errors. Such automation can also free operators to concentrate on the cognitive level of operations. The subject of automation and AI affects control room design, operating procedures, and other operator aids, staffing, and training. The staff is investigating the benefits and hazards of increased automation in the nuclear industry and will consider incentives to encourage the industry to move toward automation as a means to increase plant safety.

CONCLUSION

This item is covered in Item HF5.2.

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1209. NUREG-1358, "Lessons Learned from the Special Inspection Program for Emergency Operating Procedures," U.S. Nuclear Regulatory Commission, April 1989.

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SECTION 5

CHERNOBYL ISSUES

The staff's assessment of the implications of the Chernobyl accident on the safety regulation of U.S. commercial nuclear power plants, as reported in NUREG-1251,[1174] led to the conclusion that no immediate changes in NRC's regulations regarding the design or operation of U.S commercial reactors were needed. However, further consideration of certain issues was recommended, most of which were found to be already under consideration as a part of ongoing NRC work.

This section includes all the work recommended in NUREG-1251[1174] and outlined in the staff's follow-up program, SECY-89-081.[1175] As noted in NUREG-1251,[1174] the Chernobyl experience will continue to be taken into account in various areas of reactor safety. The follow-up program was limited to work on those issues whose relationship to the events at Chernobyl is direct, clear, and substantial, but with reasonable extrapolation to account for the large differences in specific design and operational features. Other work that may be related generally to severe accidents will be pursued (or considered for pursuit) in accordance with established procedures outside the Chernobyl follow-up program.[1175]

The tasks contained in this section follow the numbering sequence of the various chapters in NUREG-1251.[1174] The issues identified for further pursuit under each task follow the labeling of the follow-up program.[1175]

TASK CH1: ADMINISTRATIVE CONTROLS AND OPERATIONAL PRACTICES

This task, outlined in Chapter 1 of NUREG-1251,[1174] called for the staff to review the administrative controls over plant operations in the U.S. to determine if adequate controls are in place to maintain plant conditions within the safe operating envelope. This review will include an assessment of procedural adequacy and compliance, approval of tests, bypassing of safety systems, availability of engineered safety features (ESF), operating staff attitudes toward safety, management systems, and accident management.

ITEM CH1.1: ADMINISTRATIVE CONTROLS TO ENSURE THAT PROCEDURES ARE FOLLOWED AND THAT PROCEDURES ARE ADEQUATE

This item consists of two recommendations that are evaluated separately below.

ITEM CH1.1A: SYMPTOM-BASED EOPs

DESCRIPTION

During the Chernobyl event, serious operational errors aggravated the emergency situation that existed and were considered to be a major contributor to the disastrous consequences that ensued. Although design and operational control protections at U.S. reactors provide assurance against the chain of events that occurred at Chernobyl, the Chernobyl experience suggests that closer attention should be paid to effective emergency procedures and the ability of operators to use them. Symptom-based EOPs and their full implementation are a key part of the necessary preparedness for effective management of emergencies. Recent audits by the NRC have identified deficiencies in the implementation of the new symptom-based EOPs. In addition, NRC examinations have identified the need for additional training in the use of these EOPs. The staff has undertaken an accelerated inspection program of EOPs which is aimed at evaluating their technical correctness and their ability to be physically and correctly carried out. This program consists of a four-team effort encompassing four units of each of the four reactor vendor types. Possible regulatory action to upgrade this program or possible further study of any inconclusive results will be considered following staff review of the results of this inspection program.

This issue is directed towards integration of Chernobyl lessons into the staff's EOP effort and is expected to increase the staff's knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, it is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH1.1B: PROCEDURE VIOLATIONS

DESCRIPTION

Procedure violations at nuclear power plants are committed by licensed and auxiliary operators, plant technicians, maintenance personnel, and contractors. While the NRC believes that these violations are infrequent and only rarely occur with the knowledge that they are being committed, the exact nature and extent of these violations and their consequences are basically unknown. At Chernobyl, serious procedure violations were a key factor in the cause of the accident. This issue called for the staff to identify procedure violations committed at nuclear power plants, evaluate their consequences, and, if warranted, recommend options for regulatory actions to minimize future violations. The staff will focus initially on those procedure violations associated with reactor scrams or scram signals and will address the following:

(a) Analyze incident reports and other descriptions of major events and identify procedure violations that contributed to initiation of the events or that occurred during the events.

(b) Conduct a literature search for other sources of documented procedure violations associated with reactor scrams or scram signals.

(c) Review the special study AEOD/S801[1176] for incidences of procedure violations.

(d) Develop Sequence Coding and Search System (SCSS) search criteria and review LERs for reports of procedure violations. The LER search will be limited to the period 1983 to the present.

(e) Analyze the above data and develop and implement an approach for their presentation that will provide: (1) the kinds of procedure violations and the personnel involved; (2) the frequency of procedure violations involving reactor scrams; (3) the consequences of these violations, including challenges to ESF, and actual or potential releases of radioactive materials; and (4) the frequency of procedure violations with significant consequences.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue considered is to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH1.2: APPROVAL OF TESTS AND OTHER UNUSUAL OPERATIONS

This item consists of two recommendations that are evaluated separately below.

ITEM CH1.2A: TEST, CHANGE, AND EXPERIMENT REVIEW GUIDELINES

DESCRIPTION

Planned tests and experiments not described in licensees' SARs and changes to facilities and procedures described in these reports are required to be evaluated beforehand by licensees, in accordance with 10 CFR 50.59, to assure their safety and that the NRC is afforded the opportunity to review them where appropriate. Thousands of these reviews are successfully conducted by licensees each year; however, in some instances, these reviews have not been adequate. As a result, the NRC was not always afforded the opportunity to review those tests, experiments, and changes that involved an unreviewed safety question before they were performed. Without appropriate reviews by licensees and the NRC, tests could be performed without adequate safety provisions or some safety features could be unacceptably altered, a condition that could remain undetected for lengthy periods. The Chernobyl accident occurred during a test and the lack of adequate planning review, preparation, and implementation of the test emphasizes the need for attention to this issue.

The need for review guidance for tests, changes, and experiments was identified before the Chernobyl accident and is being addressed by a NUMARC/NSAC Working Group and by the NRC Technical Specifications Branch in the Technical Specifications Improvement Program (TSIP). The NUMARC/NSAC Working Group will develop draft criteria and guidelines and provide them to the industry and the NRC for review and comment. When acceptable to the Working Group and a consensus of the industry agrees, the NRC will review the guidance document which will be made available to all licensees and may be supplemented if necessary to permit NRC endorsement. The industry and the NRC will use the guidance in their review of tests, experiments, and changes required by 10 CFR 50.59. The scope of this issue is limited to coordination to assure appropriate introduction of Chernobyl lessons into the ongoing program.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

An NRC Working Group consisting of seven members and two ad hoc members was formed in July 1987 to coordinate with NUMARC/NSAC the development of guidance for 10 CFR 50.59 reviews including tests, experiments, and changes and to recommend an endorsable product to NRC management. Regional coordinators have been named to interact with the Working Group and to assist it in various requests, including comment requests on NUMARC/NSAC draft documents. Two drafts of the NUMARC/NSAC Working Group "10 CFR 50.59 Guidance Document" have been forwarded to the NRC for comment.

ITEM CH1.2B: NRC TESTING REQUIREMENTS

DESCRIPTION

There is a potential for human error when conducting tests to assess equipment capabilities. This potential represents a risk to plant safety which can vary in severity depending both on the nature of the tests and the circumstances associated with them. Tradeoffs between the risks of not testing or of testing at a lesser frequency and the risks associated with such testing have not always been assessed. The Chernobyl accident occurred when the unit was used for a test. This issue called for the staff to determine if there are any post-startup equipment tests whose conduct presents a sufficient potential impact on plant safety to suggest either their modification, reduced frequency, or elimination.

The staff will review NRC-required post-initial-startup equipment tests at nuclear power plants to identify those tests where human error could result in risks to plant safety. For this issue, "risk to plant safety" is defined as a reactor scram or scram signal, a challenge to ESF, unanticipated releases of radioactive materials, or any other evident unacceptable plant condition. The staff will quantify the potential risk for such tests and recommend a revised testing requirement for those with excessive risk. In resolving this issue, the staff will:

(a) Devise search criteria and conduct a search of the SCSS data bank of LERs to identify reported cases of human error associated with the conduct of plant equipment tests. The search will cover the period 1984 to the present.

(b) Screen the LER data collected to identify for further study those errors that resulted in reactor trips, challenges to ESF, unanticipated releases of radioactivity, or other evident unacceptable plant conditions. The objective is to order the LERs in terms of their results and to screen out those human errors, e.g., failure to conduct a test on time, which have no immediate consequence potential.

(c) Conduct a literature search for other analyses or descriptions of human error and resulting non-trivial consequences associated with plant testing.

(d) Using the above data, prepare a preliminary estimate of the potential risk to plant safety caused by human error during equipment testing. This estimate should support a recommendation to terminate this issue or to continue with more detailed risk/benefit analyses that could provide additional scope to the Performance Evaluation of Technical Specifications (PETS) program or support revisions to NRC testing policy.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH1.3: BYPASSING SAFETY SYSTEMS

This item consists of one recommendation that is evaluated below.

ITEM 1.3A: REVISE REGULATORY GUIDE 1.47

DESCRIPTION

The bypassing of safety functions by inadvertently bypassing redundant divisions of safety systems for test or maintenance purposes should be prevented. Safety system bypass was a key part of the cause of the Chernobyl accident. This issue called for the staff to recognize the lessons of Chernobyl in ongoing work to revise and improve Regulatory Guide 1.47.[150] The scope of this issue includes improved methods for indication of individual division bypass conditions and improved administrative controls over individual division bypasses. Completion of this issue will also resolve TMI Action Plan[48] Item I.D.3, "Safety System Status Monitoring." In revising Regulatory Guide 1.47,[150] the staff will: (a) evaluate the implications of bypassing safety systems; (b) recommend improved procedures and methods to prevent inadvertent bypassing of safety functions during test or maintenance; and (c) prepare revised Regulatory Guide 1.47 to reflect (a) and (b).

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

This item is being purused by the staff.

ITEM CH1.4: AVAILABILITY OF ENGINEERED SAFETY FEATURES

This item consists of three recommendations that are evaluated separately below.

ITEM CH1.4A: ENGINEERED SAFETY FEATURE AVAILABILITY

DESCRIPTION

ESF equipment needed to mitigate DBAs and transients currently have operability requirements in the TS to assure their availability for all modes of operation. In some instances, all of this equipment has not been evaluated in light of the need for its availability for plant shutdown modes. This issue called for the staff to evaluate and specify operability (availability) requirements for those ESF and support systems needed to mitigate DBAs and transients.

The issue will be addressed in the TSIP and is part of an overall program to ensure that the Owners' Groups and individual licensees specify the appropriate plant status modes for ESF equipment. In some of the older TS, mode requirements for operability may not be specified for other than the power operating mode. In the rewrite of the "Bases" sections of the TS, the reasons for LCOs will be included. Where the mode is currently absent or is inappropriately specified, the Bases will be clarified to identify required ESF equipment for each operational condition. However, ESF-required availability will only be addressed with respect to DBAs and transients and initial conditions (modes) currently analyzed in FSARs.

Reactor-vendor-based Owners' Groups will be permitted to remove those specifications in current STS that do not meet Commission criteria for what should be included in the TS. Requirements remaining in the TS will be rewritten and improved. Each rewritten and improved TS must have a Bases section that not only explains why a TS is needed, but also explains the plant conditions for which it is needed. This need will be evaluated for all of the operating modes of the plants.

Licensees will be encouraged to convert to the new STS and conduct similar upgrades for plant-unique specifications that meet the NRC criteria for the TS. These plant upgrades will be done on a voluntary basis. Those licensees participating will have appropriate ESF operability requirements specified for plant conditions where equipment could be needed for accident mitigative purposes. Upgraded plant-unique TS will also be evaluated. If significant ESF availability disparities are disclosed in this upgrade, they will be recommended for backfit on non-program participants' TS as the need arises.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH1.4B: TECHNICAL SPECIFICATIONS BASES

DESCRIPTION

Current TS Bases do not always provide a clear and comprehensive discussion linking specific requirements to the safety analysis assumptions they are derived from. This can result in operators not being as aware as possible of the safety significance of certain types of TS violations, an issue that may have had a counterpart at Chernobyl. It can also result in TS changes being proposed without adequate consideration of all the relevant safety issues. This issue called for the staff to develop an upgraded set of Bases for the STS to provide a clearer link between requirements and the safety analysis. The upgraded standard Bases will be made available to individual licensees for the purpose of adapting them to their plants as part of a voluntary industry-wide program to improve the TS.

It is planned that a separate set of upgraded standard Bases will be developed for each LWR design. The upgraded Bases will be developed as part of an ongoing joint NRC/Industry Technical Specifications Improvement Program (see

SECY-86-310) that was initiated prior to the Chernobyl event. This is a program whereby the industry/utility owners' groups will completely rewrite the STS (including the Bases), making improvements in both format and content. Once the new STS are developed, it is expected that most utilities will voluntarily elect to adopt them for their plants. Any decision to require an individual licensee to convert to the new STS will be made in accordance with the Backfit Rule (10 CFR 50.109). This issue is limited to the introduction of Chernobyl lessons into the staff's ongoing work and no separate work beyond that already started under the TSIP is planned. The Bases rewrite part of the Improvement Program will be comprehensive. A clear one-to-one relationship between TS requirements and the safety analysis will be documented in a carefully formatted Bases section for each TS. Separate Bases subsections will be written to address separate parts (i.e., LCOs, Action Statements, and Surveillance Requirements) of each plant's TS.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

No incremental work attributable to Chernobyl lessons will be necessary to complete this issue. The only additional resources necessary will be those required to report progress against the Chernobyl Follow-up Research Plan and write a closeout report.

ITEM CH1.4C: LOW POWER AND SHUTDOWN

DESCRIPTION

The Chernobyl event occurred when the unit was in a state of low power. In contrast, most regulatory attention and virtually all PRAs have focused on a state of full power operation. This issue called for the staff to perform an analysis of the core damage frequency and risk associated with a plant being in a state of low power or shutdown. The staff will examine the probabilistic risk from potential accidents initiated during shutdown and low power conditions at the Surry nuclear power plant.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

The contract work on this task is being done as a part of the Accident Sequence Evaluation Program. Potential reactivity accident sequences that could originate at low or zero power are included in the scope of Item CH2.1A, "Reactivity Transients," the results of which may provide input to this issue.

ITEM CH1.5: OPERATING STAFF ATTITUDES TOWARD SAFETY

DESCRIPTION

A significant aspect of the Chernobyl accident involved operator decisions and actions that reflected an apparent loss of the sense of vigilance toward safety and ultimately led to operators allowing operations outside the safe operating envelope. Some potential causes of this unacceptable attitude were: (1) pressure on the operators to complete a test during the reactor shutdown as the next opportunity would have been more than a year away; (2) test delay may have aggravated operator impatience and contributed to a "mindset" that led to imprudent safety actions; (3) operators, being so intent on establishing acceptable power level for the test, may have ignored the unstable state of the reactor; and (4) a clear failure to appreciate the basic reactor physics of the RBMK reactor. The accident raised the question whether licensed operators, senior operators, and other staff at nuclear power plants in the U.S. have and maintain an acceptable level of vigilance toward safety when operating commercial nuclear power plants.

In pursuing this issue, the staff increased its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Thus, the issue was considered to be a licensing issue.

CONCLUSION

The staff believes that safeguards against unacceptable operator and plant personnel attitudes toward safety are adequate. This conclusion is based on the significant increase in the quality of training, industry initiatives in accrediting training programs, and regulatory and industry oversight inspections. Thus, this Licensing Issue has been resolved.

ITEM CH1.6: MANAGEMENT SYSTEMS

This item consists of one recommendation that is evaluated below.

ITEM CH1.6A: ASSESSMENT OF NRC REQUIREMENTS ON MANAGEMENT

DESCRIPTION

Management oversight at all levels must be effective to ensure that tests, maintenance, and operations are conducted safely and that NRC requirements are enforced. The NRC is developing improved methods of monitoring licensee management performance to give early warning of management problems and to initiate enforcement mechanisms. It is also important to ensure that the monitoring and evaluation of management systems consider management capability to handle emergencies and the immediate effects of an accident. Issues of importance include management measures to ensure the availability of personnel capable of handling emergencies, planning for the operation of plant controls and systems with severe core damage, and plant staff training for operation under severe emergency conditions. At the same time, it is important that NRC-imposed requirements on management be reasonable and without excessive burdens that could divert from critical responsibilities. Management failure to recognize and respond appropriately to hazardous conditions was a major factor in the Chernobyl accident. This issue called for the staff to ensure that NRC research programs involving the review or evaluation of utility management include the management issues arising from the Chernobyl event, with particular attention to matters important to safety and to avoidance of excessive burdens that could divert that attention.

The staff will coordinate activities of the following research programs that focus on the performance of utility management to ensure that the concerns of this issue are being addressed cohesively: (1) Management/Organization Influence on Human Error Rates; and (2) Programmatic Performance Indicators. Activities of any new research programs in this area, e.g., Severe Accident Management, will be coordinated for the same purpose. The staff will also coordinate the development of the following evaluation techniques: (a) Management capability to handle severe accidents of the Chernobyl scale; (b) Management measures requiring the availability of personnel capable of handling emergencies of the type experienced at Chernobyl; (c) Management programs for training personnel to handle emergencies; and (d) Management plans for the operation of plant controls and systems to cope with severe core damage. Coordination will be extended to the following identified user needs as these needs are translated into research programs: (1) Operator Performance Under Stress of Emergency Operations; and (2) Severe Accident Management.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH1.7: ACCIDENT MANGEMENT

This item consists of one recommendation that is evaluated below.

ITEM CH1.7A: ACCIDENT MANAGEMENT

DESCRIPTION

The consideration of severe accidents in current symptom-based procedures typically does not go beyond the area of inadequate core cooling. This issue called for the staff to coordinate NRC research activities and programs dealing with severe accident management to ensure the appropriate incorporation of insights gained from the Chernobyl event. This may involve the review of severe accident management programs that may be implemented at existing nuclear power plants. The staff will: (a) assist in scoping the training, organization and habitability elements of new research programs addressing severe accident management to incorporate the Chernobyl lessons learned; (b) review ongoing NRC severe accident management programs and recommend modifications as needed to include the insights gained from the

Chernobyl event; and (c) participate in NRC reviews of individual plant severe accident management programs and determine the extent to which these programs have taken advantage of the insights gained from the Chernobyl event.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

REFERENCES

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

150. Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems," U.S. Nuclear Regulatory Commission, May 1973.

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Volumes I and II) April 1989.

1176. AEOD/S801, "Significant Events that Involved Procedures," Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, March 1988.

TASK CH2: DESIGN

The Chernobyl Unit 4 accident was a prompt critical reactivity excursion that occurred when the operators reduced power to well below the permissible safe operating level and, at the same time, neglected to follow low power operating procedures. Unit 4 shared a site with Units 1, 2, and 3 and was contiguous with Unit 3 with which it also shared some common elements. All three of the other units were exposed to some danger from the accident. Fires aggravated the accident and complicated its management and consequences. In this task, outlined in Chapter 2 of NUREG-1251,[1174] the staff will compare the design features of U.S. reactors with those of the Chernobyl 4 reactor in looking for possible regulatory changes implicit in the accident.

ITEM CH2.1: REACTIVITY ACCIDENTS

This item consists of one recommendation that is evaluated below.

ITEM CH2.1A: REACTIVITY TRANSIENTS

DESCRIPTION

In light of Chernobyl, it is necessary to examine some of the multiple-failure reactivity transients using PRA tools to reconfirm previous judgments. This item called for the staff to perform a study to estimate probability levels of certain reactivity transients. If any events appear to fall within the probability levels of NRC guidelines and involve a significant potential for extensive core damage, they might become a basis for changing design or operational limits. The study will include both probabilistic analyses to estimate the frequency of an event and deterministic analyses to assess the potential consequences. The events of interest are those in which there is a relatively large reactivity insertion and/or the response of the shutdown system may be inadequate. Identified events of interest are:

BWRs

- Multiple rod drop
- Control rod ejection
- Overpressurization with limited relief
- Boron dilution during anticipated transient without scram (ATWS)
- ATWS without recirculation pump trip
- Multiple rod bank withdrawal
- Reactivity events with more than one rod stuck out

PWRs

- Multiple rod blank withdrawal ATWS
- Multiple rod ejection (low power)
- Injection of cold, unborated emergency cooling water
- Injection of cold, unborated water due to SGTR

- Unlimited boron dilution
- Rod withdrawal, heatup or depressurization from low temperature with positive moderator temperature coefficient
- ATWS with less negative moderator temperature coefficient
- Reactivity events with more than one rod stuck out

In addressing this issue, the staff will focus attention on sequences that might involve a positive void coefficient or moderator temperature coefficient, that might arise in connection with deliberate bypassing or disabling of any safety feature, and whose causes include human error (commission, omission, or misjudgment).

The six parts of this issue are as follows:

I. Establishment of Criteria: Criteria will be established to judge whether a particular sequence needs further examination by the NRC.

II. Selection of Events: Sequence of event trees will be developed for the events identified above and critical sequence paths will be determined for different modes of reactor operation in light of positive moderator temperature coefficient, deliberate bypassing or disabling of any safety feature and human errors including commission, omission, and misjudgments. One typical Westinghouse PWR (Byron) and one typical BWR (Peach Bottom) were chosen to be analyzed. If certain sequences in certain events are important, analyses will be extended to other types of plants.

III. Probabilistic Quantification of Events: The accident sequences that emerge from Part II will be quantified to establish those that meet criteria in Part I above. The quantification process will involve a detailed search of various data bases to obtain failure rates and event probabilities. If the data base is not available, such as in the case of human errors, conservative assumptions will be made.

IV. Physical Assessment of Events: For each sequence of events for which the frequency of occurrence is either unknown or expected to be significant according to the criteria of Part I, a deterministic analysis will be made. Key parameters will be determined and their limiting values quantified. The quantification will be done primarily by using results of analyses which have already been performed for other purposes.

V. Preparation of Report: A draft report will be prepared integrating the above described tasks.

VI. Final Report: A final report will be prepared after comments.

CONCLUSION

This item is being pursued by the staff.

ITEM CH2.2: ACCIDENTS AT LOW POWER AND AT ZERO POWER

DESCRIPTION

One of the unique aspects of the Chernobyl accident is that it occurred at relatively low power (<7%). This has caused some concern because low power operation is generally considered to be a safer condition than high or full power operation. The principal effect of low power on the Chernobyl accident was related to nuclear/thermohydraulic stability and reactivity insertion. These effects were addressed in Item CH2.1. Another important aspect of low power or zero power operation is the availability of safety systems. Items CH1.3 and CH1.4 specifically address the subjects of bypassing and availability of safety systems. Different safety systems may be used to provide protection for low power and shutdown (zero power) events than are used for high power events. TS prescribe the conditions for bypassing and activating the various systems and their completeness is also addressed in Items CH1.3 and CH1.4.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

Accident initiators at low power are covered in Item CH1.4 which is to be coordinated with the Severe Accident Program. The results of Item CH1.4 will be made available to the industry to help develop TS improvements if necessary.

ITEM CH2.3: MULTIPLE-UNIT PROTECTION

The radioactive gas and smoke released during the accident at Chernobyl Unit 4 spread to the other three operating units at the site. The airborne radioactive material was transported to the other units through a shared ventilation system as well as by way of general atmospheric dispersion paths. This raises the question of how accidents at one unit of a multi-unit site affect the remaining units and additional questions of how these effects may be compounded when structures, systems, and components are shared between units. This item consists of four recommendations that are evaluated separately below.

ITEM CH2.3A: CONTROL ROOM HABITABILITY

DESCRIPTION

The objective of this issue is to estimate what effects an accident at one unit of a multi-unit site could have upon the ability of site personnel to maintain the remaining units in a safe condition, to identify potential new requirements that would decrease those effects, and to assess the safety advantages of such requirements in relation to the disadvantages of their imposition. Although identified as a multi-unit issue, the staff's work should include site emergencies such as fires and other potential causes of widespread damage that might not be directly related to a particular unit. By including control room habitability challenges not initiated by a reactor accident, single unit sites would also be included.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

All efforts to address this issue are included in the plans for the resolution of Issue 83, "Control Room Habitability." Included in these plans is a survey of a sample of U.S. control rooms at diverse plants and sites and an assessment of the capabilities of these control rooms and their habitability systems to meet GDC 5 and 19. In the event of deficiencies in the assessed capabilities, the costs and benefits of backfits needed to achieve those capabilities are to be assessed and, where justified, requirements specified.

ITEM CH2.3B: CONTAMINATION OUTSIDE CONTROL ROOM

DESCRIPTION

The objective of this issue is to identify all plant areas to which human access would be necessary to either manage an accident at an affected unit or to maintain other units at a multi-unit site, to assess the dose consequences to personnel performing needed tasks within those areas, and to identify any potential measures for further reducing those consequences which could be justified by virtue of improved risk.

The necessary information to perform the work required by this issue includes identification of risk-dominant accidents and their corresponding accident management plans. For the identified accidents and the associated plant areas to which access is needed, generic estimates of contamination of those areas, in combination with generic measures of radiation shine from adjacent equipment and from other units, need to be developed.

The identification of plant areas to which access is required occurred during resolution of TMI Action Plan[48] Item II.B.2. It will be confirmed that these plant identifications are consistent with the accident management considerations being proposed in conjunction with the IPE. This work is incorporated in existing efforts in accident management research.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item consists of review and coordination to assure that Chernobyl lessons are taken into account in the Accident Management Research Plan. The results of this issue will constitute an input to the Accident Management Research efforts.

ITEM CH2.3C: SMOKE CONTROL

DESCRIPTION

This issue called for the staff to assess the risk significance of smoke propagation from one unit to an adjacent unit and to address the question of whether additional protection/requirements should be developed. The staff will use fire risk assessments from four LWRs to assess the risk significance of smoke propagation. Based upon the results, the need for further work will be determined. This issue could affect existing and future plants.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH2.3D: SHARED SHUTDOWN SYSTEMS

DESCRIPTION

This issue called for the staff to determine whether sharing of systems required for safe shutdown among units at a multi-unit site should be prohibited and, if not, to what restrictions such sharing should be subjected. The staff is to determine requirements for shared systems and prepare guidance on the use of shared systems as part of the severe accident policy implementation. It is anticipated that only future plants will be affected by this issue.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH2.4: FIRE PROTECTION

This item consists of one recommendation that is evaluated below.

ITEM CH2.4A: FIREFIGHTING WITH RADIATION PRESENT

DESCRIPTION

This issue called for the staff to determine: (1) whether there is a significant risk that radiation released during a fire or from the initiating event could limit firefighting capability; and (2) what additional measures, if any, such risk might necessitate. The staff will use existing representative fire risk studies from four LWRs to estimate risk. This issue could affect existing and future plants.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

REFERENCES

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Revision 1) August 1980.

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Volumes I and II) April 1989.

TASK CH3: CONTAINMENT

The Chernobyl accident, with its absence of effective containment, has focused attention on the strengths and performance limits of the substantial containments for U.S. LWRs. It has led to added recognition of the significance of ongoing work on the issue of whether U.S. containments that were built using criteria based on DBAs have adequate margins available to prevent the release of large quantities of fission products during severe accidents. Challenges include phenomena such as increased pressures from an uncontrolled hydrogen combustion or release of large quantities of noncondensible gases from core-concrete interactions. Venting the containment in case of certain severe accidents could be an effective way to preserve the long-term containment functional integrity and reduce the uncontrolled release of radioactive material. This task, outlined in Chapter 3 of NUREG-1251, [1174] summarizes the activities already in place in the areas of containment integrity and containment venting.

ITEM CH3.1: CONTAINMENT PERFORMANCE DURING SEVERE ACCIDENTS

This item consists of one recommendation that is evaluated below.

ITEM CH3.1A: CONTAINMENT PERFORMANCE

DESCRIPTION

This issue called for the staff to determine whether the Chernobyl containment failure indicates that changes in U.S. containment or reactor design and operation requirements are warranted. In addressing this issue, the staff is expected to reflect Chernobyl experience, where relevant, in containment reviews under the Commission's Severe Accident Policy.

An existing set of tasks relating to adequate containment performance was underway in the U.S. before the Chernobyl accident. These tasks (IPE, the development of accident management strategies, containment performance, and NUREG-1150[1081]) are related to determining whether the existing design and operation of U.S. commercial reactors provide an adequate level of safety or whether changes in regulatory guidance are required. The Chernobyl accident adds to the information base only indirectly because of differences in reactor types and containment (or confinement) approaches.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue considered is to be a licensing issue.

CONCLUSION

Efforts to address this issue are underway, as noted in SECY-87-297. No separate projects or assessments are envisaged.

ITEM CH3.2: FILTERED VENTING

This item consists of one recommendation that is evaluated below.

ITEM CH3:2A: FILTERED VENTING

The issue called for the staff to determine whether U.S. containments should be backfitted with filtered vents to mitigate the consequences of severe accidents as is being proposed and implemented in Europe. The Chernobyl accident heightened interest in this issue, though the issue itself has no specific Chernobyl counterpart. The purpose of this issue is to develop information to be used in assessing filtered vents proposed for U.S. reactors and to advise the Commission on whether such systems should be required for specific categories of U.S. reactors. The staff will assess the filtered venting technology emerging from European research and applications for potential U.S. reactor severe accident improvements. This work is a non-distinguishable part of the development of accident management strategies and containment performance assessments.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue considered is to be a licensing issue.

CONCLUSION

Venting is being studied by INEL under staff contracts. This study requires an assessment of European research and applications and keeping abreast of relevant literature and participation in international evaluation activities. One such activity was the Nuclear Energy Senior Group of Experts on Severe Accidents meeting on Filtered Containment Venting Systems held in May 1988 in Paris and the preparation of a "white paper" on the technology and related issues. No separate projects or assessments arising from Chernobyl are envisaged.

REFERENCES

1081. NUREG-1150, "Reactor Risk Reference Document," U.S. Nuclear Regulatory Commission, (Draft) February 1987.

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Volumes I and II) April 1989.

TASK CH4: EMERGENCY PLANNING

A number of facts about the Chernobyl accident have some bearing on emergency planning and preparedness around U.S. commercial nuclear power plants. This task, outlined in Chapter 4 of NUREG-1251,[1174] called for the staff to examine the implications of the accident and the Soviet response for four aspects of U.S. emergency planning: (1) size of the emergency planning zone (EPZ); (2) medical services; (3) ingestion pathway measures; and (4) decontamination and relocation.

ITEM CH4.1: SIZE OF THE EMERGENCY PLANNING ZONES

DESCRIPTION

The Chernobyl accident focused attention on the adequacy of the size of EPZs around U.S. commercial nuclear power plants. The Soviets evacuated a total of about 135,000 people as well as considerable farm livestock from Pripyat, Chernobyl, and other towns and villages within 18 miles of the Chernobyl power plant. This evacuation appears to have taken place in several stages, beginning for the approximately 45,000 residents of Pripyat about 36 hours after the initial release and extending over several days to a week. The whole-body radiation dose to the majority of individuals did not exceed 25 rem, although about 24,000 persons in the most severely contaminated areas are estimated to have been exposed to whole-body doses in the range of 35 to 55 rem. The population of Pripyat was initially sheltered as a protective measure and then evacuated when radiation readings increased. In addition to radiation considerations, logistics and contamination control influenced the timing of the evacuation. Despite an apparent lack of site-specific planning, the Soviets mounted a large and generally effective ad hoc response making use of some aspects of civil defense planning. The high initial plume contributed to relatively low initial dose rates in the immediate vicinity. In addition, efforts by the Soviets to prevent rainfall in the immediate vicinity (by cloud seeding other areas) and the spraying of a chemical polymer on evacuation routes to minimize resuspension of deposited activity were also beneficial. The Soviets took ingestion pathway protective measures within the 18-mile zone and well beyond. Ingestion pathway protective measures were also taken in several Soviet bloc countries, in Scandinavia, and in Eastern and Western Europe.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

The Chernobyl accident and the Soviet response did not reveal any apparent deficiency in U.S. plans and preparedness, including the 10-mile plume exposure pathway EPZ size and and the 50-mile ingestion exposure pathway EPZ size. These zones provide an adequate basis to plan and carry out the full range of protective actions for the population within these zones as well as beyond them, if the need should arise. Any changes in EPZ sizes should be based on revised insights coming from current U.S. research on severe accident releases. No recommendation resulted from this item which was dropped from further consideration.

ITEM CH4.2: MEDICAL SERVICES

DESCRIPTION

At Chernobyl, KI was distributed to school children within about 6 hours of the accident and to the entire population of Pripyat the morning of the following day; ultimately, it was given to the population in the 18-mile zone and other areas. The Soviets reported no serious adverse reactions to KI. Polish authorities also distributed KI to the population in parts of eastern Poland. This issue called for the staff to review the adequacy of the U.S. Government's policy on KI and the adequacy of medical services around U.S. nuclear power plants.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

The apparently successful use of KI by the Soviets did not alter the validity of U.S. Government policy that predistributing or stockpiling KI for use by the general public should not be required; rather, this decision should be made by individual States and by local authorities. Further, the staff concluded that the present arrangements and future plans for medical services around U.S. commercial nuclear power plants are adequate. The national capability is both substantial and growing. Also, the international offers of medical support to the Soviet Union following the Chernobyl accident demonstrate that the U.S. regional and national medical response can be augmented, if necessary by a response from the international medical community. No recommendation resulted from this item which was dropped from further consideration.

ITEM CH4.3: INGESTION PATHWAY MEASURES

This item consists of one recommendation that is evaluated below.

ITEM CH4.3A: INGESTION PATHWAY PROTECTIVE MEASURES

DESCRIPTION

After the Chernobyl accident, human and animal food chains in the Soviet Union and other European countries were contaminated to varying degrees. The Soviet and other affected governmental authorities took measures, both short-term and long-term, to protect the public from receiving unacceptably high levels of radiation through consumption of contaminated food. The contamination level findings and the experience with the Soviet and other European control measures could provide important extensions of the data base for planning of protective measures in the U.S. This issue called for the staff to participate with FEMA and other Federal and appropriate international agencies in planning and eventual execution of efforts to obtain available information on the Soviet and other European post-Chernobyl ingestion pathway contamination and control measures experience and analyze that information in relation to U.S. understanding of the issue.

The work is expected to be done primarily under FEMA's coordination together with other appropriate Federal agencies, such as FDA and EPA, and international agencies such as IAEA. The NRC will participate in this work to assure adequate representation of NRC's interest in the effort and to obtain the information needed for NRC's purposes. The information to be sought is expected to encompass contamination level findings for various human and animal foodstuffs, as well as water bodies, including variation with time and place, and the nature, timing, effectiveness, and problems of various protective measures taken by the affected countries. Future analyses are expected to relate findings to U.S. source term research results. The work of CY 1988 is expected to be devoted primarily to establishment of interagency and international contracts and arrangements and development of a research plan, in cooperation with FEMA and other agencies. The plan is expected to encompass both near-term work, focusing on the short-term experience, and long-term plans for a number of future years, for lessons of the long-term experience.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH4.4: DECONTAMINATION AND RELOCATION

This item consists of two recommendations that are evaluated separately below.

ITEM CH4.4A: DECONTAMINATION

DESCRIPTION

The practicality and effectiveness of measures to decontaminate structures, land, etc. after a major accident can be a significant factor in evaluation of accident consequences as well as in formulation of plans and approaches for post-accident decontamination. The experience with post-Chernobyl decontamination in the Soviet Union could provide important extensions of the data base. This issue called for the staff to participate with FEMA and other Federal and international agencies in planning and eventual execution of efforts to obtain available information on the Soviet post-Chernobyl decontamination experience and analyze that information in relation to U.S. understanding of the issue.

The work is expected to be done primarily under FEMA's coordination, together with other appropriate federal agencies such as EPA and FDA and international agencies such as IAEA. The NRC will participate in this work to assure adequate representation of NRC's interest in the effort and to obtain the information needed for NRC's purposes. The information to be sought is expected to encompass methods, timing, and effectiveness of decontamination of various areas and objects. Future analyses are expected to relate findings to U.S. source term research results. The work in CY 1988 is expected to be devoted primarily to establishment of interagency and international contacts and arrangements and development of a research plan, in cooperation with FEMA and other agencies, in connection with acquisition and analysis of Soviet information that may become available over the next several years.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH4.4B: RELOCATION

DESCRIPTION

Notwithstanding cultural and socioeconomic differences, the Soviet experience in connection with post-accident evacuation and relocation of the population of contaminated towns and villages near the Chernobyl reactor may well offer valuable lessons for U.S. emergency planning. This issue called for the staff to participate, with FEMA and other appropriate Federal and international agencies, in developing plans and arrangements for learning about and from the Soviet post-Chernobyl relocation experience.

Plans and interagency and international arrangements will be developed, under FEMA coordination, together with other Federal agencies and international bodies such as IAEA. Logistical, socioeconomic, health, and psychological considerations are expected to be included in the information to be sought.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

REFERENCES

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Volumes I and II) April 1989.

TASK CH5: SEVERE ACCIDENT PHENOMENA

The highly energetic reactivity excursion accident at Chernobyl mechanically disrupted the core, rapidly vaporized the water coolant with which the fragmented fuel came into contact, and generated combustible hydrogen by chemical reaction of core materials (notably zirconium) and water at the high temperatures reached in the accident. Because of basic design differences between the RBMK reactor of Chernobyl and U.S. LWRs, the specific accident mechanisms involved at Chernobyl have no exact parallel in U.S. reactors. However, this task, outlined in Chapter 5 of NUREG-1252,[1174] called for the staff to assess Chernobyl phenomena for analogous implications of radionuclide releases, steam explosions, and combustible gas generation and deflagration control in U.S. reactors.

ITEM CH5.1: SOURCE TERM

This item consists of two recommendations that are evaluated separately below.

ITEM CH5.1A: MECHANICAL DISPERSAL IN FISSION PRODUCT RELEASE

DESCRIPTION

The initial release of fission products that occurred at Chernobyl was the result of mechanical dispersion. Such a mechanism is possible in LWRs within the containment during energetic events such as high pressure melt ejection, steam explosions, and hydrogen combustion. Although such events are being studied with regard to their likelihood of occurrence and their consequences, associated mechanical releases of fission products have not been quantified in current source term models and the study of such releases has only just begun to receive attention. Because some of these phenomena appear to have played a dominant role in the releases at Chernobyl, it is important to understand these phenomena more completely. This issue called for the staff to introduce the Chernoby lessons into ongoing work to improve the understanding of mechanical dispersal phenomena and to improve the modeling in NRC source term assessment codes.

Current research on mechanical dispersion is being performed in three specific areas: direct containment heating (or high pressure melt ejection), steam explosions, and hydrogen combustion. For direct containment heating, the scope of current research is to develop a capability to analyze the consequences of this phenomenon. This can be accomplished by generating an experimental data base and, by developing an analytical model based on this data base which will be subsequently incorporated in an integrated code for containment analyses. In the area of hydrogen combustion, present work includes a scoping study on mechanisms of aerosol resuspension and volatilization during hydrogen combustions. Specifically, experiments are being conducted to investigate the resuspension of aerosols (radioactive or otherwise) that have been previously deposited on containment surfaces, by mechanical or thermal processes during the occurrence of hydrogen combustion, and to investigate the volatilization and expulsion of airborne aerosols in the containment by similar processes.

The new information will subsequently be incorporated into the lumped parameter code HECTR and the finite difference code HMS-BURN for consequence analyses.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH5.1B: STRIPPING IN FISSION PRODUCT RELEASE

DESCRIPTION

The late enhanced release of fission products during the Chernobyl accident may be attributable to the chemical and/or thermal stripping of UO_2 fuel. Such mechanisms have been observed in in-pile and out-of-pile experiments when UO_2 fuel rods were exposed to steam or high temperatures and other severe degraded core conditions. During the process of thermal stripping, for example, fission products were released in proportion to the amount of UO_2 vaporized. The rate of fission product release is thus controlled by UO_2 vaporization.

Fission product release by chemical and thermal stripping mechanisms is not modeled in current severe accident source term codes. The Chernobyl accident has demonstrated that such mechanisms can be important in fission product release under some conditions. This issue called for the staff to introduce Chernobyl lessons into the continuing research on chemical and thermal stripping and to obtain sufficient data for model development and assessment.

The scope of present research on UO_2 stripping is to complete ongoing experiments investigating thermal stripping mechanisms, to collect and review experimental data on chemical stripping mechanisms from Severe Fuel Damage Program participants, and to apply both the thermal stripping and chemical stripping data to improve present fission product release codes. For chemical stripping, the present experimental program may have to be expanded to study UO_2 stripping by air oxidation. This recommendation involves coordination to assure that the ongoing work adequately reflects the Chernobyl lessons.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH5.2: STEAM EXPLOSIONS

This item consists of one recommendation that is evaluated below.

ITEM CH5.2A: STEAM EXPLOSIONS

DESCRIPTION

No specific research is currently underway or planned on reactivity insertion accident (RIA) prompt-burst steam explosions with fuel-vapor-driven fragmentation and mixing of the molten fuel and water that are relevant to the Chernobyl accident. Such work is currently not believed to be necessary, subject to confirmation in the light of results of the Chernobyl follow-up reactivity transient study (Item 2.1A).

The vapor-driven fragmentation and mixing of the interspersed fuel and coolant in prompt-burst power excursions in the Chernobyl accident has been strongly contrasted in the past to the pouring mode of contact found in the slow meltdown situations relevant to current U.S. commercial reactors. Hence the Chernobyl accident has little relevance to the staff's current treatment of steam explosions and alpha-mode containment failure. This issue called for the staff to characterize RIA steam explosions.

Current steam explosion research consists primarily of developing and assessing the semi-mechanistic Integrated Fuel Coolant Interaction (IFCI) computer model, which includes hydrogen generation, for integration into an in-vessel melt progression code. IFCI provides a mechanistic treatment of both the pre-explosion mixing phase and the explosion phase (if conditions permit), but IFCI does require a parametric input trigger for the explosion. Work is also continuing on using existing experimental data for modeling the non-explosive mixing phase of the interaction.

If further work for U.S. reactors on RIA steam explosions is found to be needed, this would be performed as part of an overall investigation of RIAs and it is in this context that the specific work scope would be planned. Currently work is underway to assess the effect of in-vessel steam explosions on in-vessel core melt progression in light-water reactor accidents.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, this issue is considered to be a licensing issue.

CONCLUSION

This item is being pursued by the staff.

ITEM CH5.3: COMBUSTIBLE GAS

DESCRIPTION

The Soviet RBMK design utilizes large amounts of zirconium and graphite in the reactor core, both of which may oxidize under certain conditions resulting in the generation of large quantities of combustible gases, principally hydrogen and carbon monoxide. The generation of large quantities of combustible gases was not apparently considered as part of the Soviet containment design. The Chernobyl accident produced reactor core conditions that may have led to the generation of large quantities of combustible gases which, in turn, may have influenced the evolution and consequences of the accident.

The need to deal with the generation of combustible gas, principally hydrogen, as a consequence of reactor accidents has been recognized in the U.S. since the early days of LWRs. The burning and/or detonation of combustible gases are of concern in reactor safety for several reasons. First, a large enough energy release might threaten the integrity of the containment. Second, even if the containment survived, important safety equipment might be irreparably damaged, thus increasing the severity of the accident. Furthermore, since significant amounts of hydrogen can be generated early in the evolution of a severe reactor accident (i.e., before the reactor vessel fails), combustion can result in containment failure before expulsion of the molten core, leading to the largest radioactivity releases to the environs.

CONCLUSION

In summary, although the conditions that existed during the Chernobyl accident may have caused large amounts of combustible gases to generate, it cannot be concluded from the available data that these gases were generated by some new or different mechanisms or produced consequences not previously investigated as part of severe-accident analyses for U.S. reactors. It is difficult to apply observations from the Chernobyl accident to U.S. plants because of significant design differences between the RBMK and nuclear power reactors in the United States; furthermore, the NRC staff still lacks detailed accident data. Considering the preliminary evaluation, it does not appear that any additional work is warranted solely on the basis of the Chernobyl event. The staff concludes that its current and proposed research program on combustible gas phenomena in conjunction with the study of severe accidents would be adequate for addressing this issue in U.S. reactors.

REFERENCE

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Volumes I and II) April 1989.

TASK CH6: GRAPHITE-MODERATED REACTORS

The Fort St.Vrain HTGR and DOE's N-reactor at the Hanford Reservation in Washington State are the only graphite-moderated power reactors operating in the U.S. This task, outlined in Chapter 6 of NUREG-1251,[1174] called for the staff to assess the HTGR concept (with emphasis on Fort St. Vrain) against the issues raised by the Chernobyl accident: operations, design, containment, emergency planning, and severe accident phenomena. Because the N-reactor is not licensed by the NRC and is under the authority of DOE, the implications of the Chernobyl accident for the N-reactor are to be assessed separately by DOE and others.

ITEM CH6.1: GRAPHITE-MODERATED REACTORS

This item consists of two recommendations that are evaluated separately below.

ITEM CH6.1A: THE FORT ST.VRAIN REACTOR AND THE MODULAR HTGR

DESCRIPTION

At Fort St. Vrain, a helium coolant is used which is pressurized to 700 psi and flows downward through 1/2-inch diameter holes in a fully ceramic (graphite) core. The reactor core and the entire primary coolant system, including steam generators and helium circulators, are enclosed in a pre-stressed concrete reactor vessel which, through use of inner and outer penetration seals and in conjunction with a filtered and vented confinement building, satisfies the NRC's general design criteria for reactor containment.

The MHTGR concept will utilize a fuel and reactor design that is derived from the Fort St. Vrain reactor. However, the reactor will be contained in a steel pressure vessel and the helium circulator and steam generator in a connected second steel vessel rather than full enclosure of the primary system in a single pre-stressed concrete reactor vessel. Its safety approach is based on an inherent negative power coefficient and selection of the reactor power density and vessel size such that decay heat can be removed passively from the exterior wall of the vessel during postulated accidents. Decay heat would be removed by natural convection airflows that are adequate to preclude fission product release from the fuel or unacceptable damage to the reactor vessel or to other vital reactor systems. The reference MHTGR plant would consist of four such modules and would produce a total of 550 MWe.

This item called for the staff to coordinate licensee preparation of a PRA for St. Vrain as part of the implementation of the Severe Accident Policy; the Chernobyl lessons were to be factored in the PRA.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue considered is to be a licensing issue.

CONCLUSION

The only features that the 330 MWe Fort St. Vrain reactor, the MHTGR, and the Chernobyl design have in common are the use of a graphite moderator and gravity-driven control rods. A limited Fort St. Vrain PRA and further experiments with structural graphite were considered before the Chernobyl accident. While the Chernobyl events supported the need for such work, the imminent termination of the operation of Fort St. Vrain removed that need. The issues raised by the Chernobyl accident have not caused any new concerns about HTGR severe accident phenomena. Thus, this licensing issue was dropped from further consideration.

ITEM CH6.1B: STRUCTURAL GRAPHITE EXPERIMENTS

DESCRIPTION

There is a need to determine the impact of cracking of a graphite fuel block at Fort St.Vrain on confidence in the long-term reliability of graphite as a structural material in an HTGR reactor core. In an extreme scenario, graphite structural failure could conceivably allow the core to drop away from the control rods, causing a reactivity accident. This issue called for the staff to complete an earlier study on the combined effects of thermal and mechanical loads on structural graphite. This study would provide an improved understanding of graphite behavior.

The staff will examine PGX graphite specimens for the interaction of thermal and mechanical stresses in the same configuration used in prior H440 graphite experiments (i.e., smooth rings, uniform internal heating with diametrically opposed loads) and perform tests to include a notch in the PGX graphite. This will permit examination of the sensitivity of the behavior of PGX structural components to combined thermal and mechanical stresses when a stress riser is present

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue considered is to be a licensing issue.

CONCLUSION

Since Fort St. Vrain (FSV) has indicated it intends to terminate operation in 1990, additional experiments on FSV graphite structural integrity will not be done. Graphite structural integrity for the MHTGR will need to be established by the applicant to support licensing this design. The staff will review the proposed MHTGR graphite structural criteria and its supporting basis as part of any application submittal. Therefore, no additional work is planned at this time on this issue.

ITEM CH6.2: ASSESSMENT

DESCRIPTION

Administrative control and operational practices at Fort St. Vrain, although generally similar to those of LWRs, originally contained some differences believed to reflect the unique features of the HTGR concept. In recent years, however, changes have been made to bring plant operations much closer to those of LWRs. A program to upgrade the TS is currently underway which will result in administrative controls that are comparable to those of LWRs. The Fort St. Vrain reactor also must meet the same or equivalent requirements as those for LWRs with respect to quality assurance, equipment qualification, external events, physical security, fire protection, radiation protection, and operator training and qualification.

Two important differences between HTGRs and LWRs with respect to operational safety are the slower response of HTGRs to plant transients, because of low power density, and their increased margin to fuel failure, because of the fully ceramic core. These differences formed the basis for permitting less prescription in some administrative procedures and are considered to enhance overall safety. MHTGR designers are proposing a design that utilizes inherent and passive safety features and fully automated plant control systems that will minimize the need for operator action to ensure safety, thus reducing the importance of the man-machine interface to reactor safety. This issue called for the staff to review this approach and include its findings in an SER on the MHTGR.

In pursuing this issue, the staff is expected to increase its knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety. Therefore, the issue considered is to be a licensing issue.

CONCLUSION

The staff assessed the areas of operations, design, containment, emergency planning, and severe accident phenomena and found that the implications of the Chernobyl accident have generated no new licensing concerns for HTGRs; general conclusions and those pertaining to specific areas are the same as those for LWRs. In performing its assessment, the staff reviewed the existing information related to these areas and concluded that programs underway or being considered adequately satisfy any concerns that could be generated because of the Chernobyl accident. Thus, this licensing issue has been resolved.

REFERENCE

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Volumes I and II) April 1989.

APPENDIX B

APPLICABILITY OF NUREG-0933 ISSUES TO OPERATING AND FUTURE PLANTS

This appendix contains a listing of those safety issues that are applicable to operating plants as well as future plants. The priority designations for all issues are consistent with those listed in Table II of the Introduction. This listing includes: issues that have been resolved with new requirements [NOTE 3(a)]; USI, HIGH and MEDIUM priority issues that are under development; nearly-resolved issues (NOTES 1 and 2) whose impact is not yet known; and issues that are scheduled for prioritization (NOTE 4).

Legend

NOTES:
1 - Possible Resolution Identified for Evaluation
2 - Resolution Available (Documented in NUREG, NRC Memorandum, SER or equivalent)
3(a)- Resolution Resulted in the Establishment of New Regulatory Requirements (Rule, Regulatory Guide, SRP Change, or equivalent)
4 - Issue to be Prioritized in the Future

B&W	- Babcock & Wilcox Company
CE	- Combustion Engineering Company
GE	- General Electric Company
HIGH	- High Safety Priority
I	- Resolved TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737[98]
MEDIUM	- Medium Safety Priority
MPA	- Multiplant Action
NA	- Not Applicable
TBD	- To Be Determined
USI	- Unresolved Safety Issue
W	- Westinghouse Electric Corporation

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
	TMI ACTION PLAN ITEMS						
I.A	OPERATING PERSONNEL						
I.A.1	Operating Personnel and Staffing						
I.A.1.1	Shift Technical Advisor	I	All	All	F-01	9/13/79	9/27/79
I.A.1.2	Shift Supervisor Administrative Duties	I	All	All		9/13/79	9/27/79
I.A.1.3	Shift Manning	I	All	All	F-02	7/31/80	6/26/80
I.A.1.4	Long-Term Upgrading	NOTE 3(a)	All	All		4/28/83	4/28/83
I.A.2	Training and Qualifications of Operating Personnel						
I.A.2.1	Immediate Upgrading of Operator and Senior Operator Training and Qualifications	-					
I.A.2.1(1)	Qualifications - Experience	I	All	All	F-03	3/28/80	3/28/80
I.A.2.1(2)	Training	I	All	All	F-03	3/28/80	3/28/80
I.A.2.1(3)	Facility Certification of Competence and Fitness of Applicants for Operator and Senior Operator Licenses	I	All	All	F-03	3/28/80	3/28/80
I.A.2.3	Administration of Training Programs	I	All	All		3/28/80	3/28/80
I.A.2.6	Long-Term Upgrading of Training and Qualifications	-	-	-		-	-
I.A.2.6(1)	Revise Regulatory Guide 1.8	NOTE 3(a)	All	All		-	-
I.A.3	Licensing and Requalification of Operating Personnel						
I.A.3.1	Revise Scope of Criteria for Licensing Examinations	I	All	All		3/28/80	3/28/80
I.A.4	Simulator Use and Development						
I.A.4.1	Initial Simulator Improvement	-					
I.A.4.1(2)	Interim Changes in Training Simulators	NOTE 3(a)	All	All		4/-/81	3/28/81
I.A.4.2	Long-Term Training Simulator Upgrade	-					
I.A.4.2(1)	Research on Training Simulators	NOTE 3(a)	All	All		4/-/87	4/-/87
I.A.4.2(2)	Upgrade Training Simulator Standards	NOTE 3(a)	All	All		4/-/81	4/-/81
I.A.4.2(3)	Regulatory Guide on Training Simulators	NOTE 3(a)	All	All		4/-/81	4/-/81
I.A.4.2(4)	Review Simulators for Conformance to Criteria	NOTE 3(a)	All	All		3/25/87	3/25/87
I.C	OPERATING PROCEDURES						
I.C.1	Short-Term Accident Analysis and Procedures Revision	-					
I.C.1(1)	Small Break LOCAs	I	All	All		9/13/79	9/13/79
I.C.1(2)	Inadequate Core Cooling	I	All	All	F-04	9/13/79	9/13/79
I.C.1(3)	Transients and Accidents	I	All	All	F-05	9/13/79	9/27/79
I.C.2	Shift and Relief Turnover Procedures	I	All	All		9/13/79	9/27/79
I.C.3	Shift Supervisor Responsibilities	I	All	All		9/13/79	9/27/79
I.C.4	Control Room Access	I	All	All		9/13/79	9/27/79
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	I	All	All	F-06	5/7/80	6/26/80

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	I	All	All	F-07	10/31/80	10/31/80
I.C.7	NSSS Vendor Review of Procedures	I	All	All		NA	6/26/80
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	I	All	All		NA	6/26/80
I.C.9	Long-Term Program Plan for Upgrading of Procedures	NOTE 3(a)	All	All		9/13/79	6/-/85
I.D	CONTROL ROOM DESIGN						
I.D.1	Control Room Design Reviews	I	All	All	F-08	6/26/80	6/26/80
I.D.2	Plant Safety Parameter Display Console	I	All	All	F-09	6/26/80	6/26/80
I.D.3	Safety System Status Monitoring	MEDIUM	All	All		-	-
I.D.5	Improved Control Room Instrumentation Research	-					
I.D.5(2)	Plant Status and Post-Accident Monitoring	NOTE 3(a)	All	All		NA	12/-/80
I.D.5(3)	On-Line Reactor Surveillance System	NOTE 1	All	All			
I.F	QUALITY ASSURANCE						
I.F.2	Develop More Detailed QA Criteria	-					
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	NOTE 3(a)	All	All		NA	7/-/81
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	NOTE 3(a)	All	All		NA	7/-/81
I.F.2(6)	Increase the Size of Licensees' QA Staff	NOTE 3(a)	All	All		NA	7/-/81
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	NOTE 3(a)	All	All		NA	7/-/81
I.G	PREOPERATIONAL AND LOW-POWER TESTING						
I.G.1	Training Requirements	I	All	All		NA	6/26/80
I.G.2	Scope of Test Program	NOTE 3(a)	All	All		NA	7/-/81
II.B	CONSIDERATION OF DEGRADED OR MELTED CORES IN SAFETY REVIEW						
II.B.1	Reactor Coolant System Vents	I	All	All	F-10	9/13/79	9/27/79
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	I	All	All	F-11	9/13/79	9/27/79
II.B.3	Post-Accident Sampling	I	All	All	F-12	9/13/79	9/27/79
II.B.4	Training for Mitigating Core Damage	I	All	All	F-13	3/28/80	3/28/80
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	NOTE 3(a)	All	All		TBD	NA
II.B.8	Rulemaking Proceeding on Degraded Core Accidents	NOTE 3(a)	All	All		TBD	01/25/85

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
II.D	REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES						
II.D.1	Testing Requirements	I	All	All	F-14	9/13/79	9/27/79
II.D.3	Relief and Safety Valve Position Indication	I	All	All		7/21/79	9/27/79
II.E	SYSTEM DESIGN						
II.E.1	Auxiliary Feedwater System						
II.E.1.1	Auxiliary Feedwater System Evaluation	I	NA	All	F-15	3/10/80	3/10/80
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	I	NA	All	F-16, F-17	9/13/79	9/27/79
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	NOTE 3(a)	All	All		NA	7/-/81
II.E.3	Decay Heat Removal						
II.E.3.1	Reliability of Power Supplies for Natural Circulation	I	NA	All		9/13/79	9/27/79
II.E.4	Containment Design						
II.E.4.1	Dedicated Penetrations	I	All	All	F-18	9/13/79	9/27/79
II.E.4.2	Isolation Dependability	I	All	All	F-19	9/13/79	9/27/79
II.E.4.4	Purging	-					
II.E.4.4(1)	Issue Letter to Licensees Requesting Limited Purging	NOTE 3(a)	All	All		11/28/78	NA
II.E.4.4(2)	Issue Letter to Licensees Requesting Information on Isolation Letter	NOTE 3(a)	All	All		10/22/79	NA
II.E.4.4(3)	Issue Letter to Licensees on Valve Operability	NOTE 3(a)	All	All		9/27/79	NA
II.E.5	Design Sensitivity of B&W Reactors						
II.E.5.1	Design Evaluation	NOTE 3(a)	NA	B&W			
II.E.5.2	B&W Reactor Transient Response Task Force	NOTE 3(a)	NA	B&W			
II.E.6	In Situ Testing of Valves						
II.E.6.1	Test Adequacy Study	NOTE 3(a)	All	All		TBD	TBD
II.F	INSTRUMENTATION AND CONTROLS						
II.F.1	Additional Accident Monitoring Instrumentation	I	All	All	F-20, F-21 F-22, F-23 F-24, F-25	9/13/79	9/27/79
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	I	All	All	F-26	7/2/79	9/27/79
II.F.3	Instruments for Monitoring Accident Conditions	NOTE 3(a)	All	All		NA	12/-/80

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
II.G	ELECTRICAL POWER						
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	I	NA	All		9/13/79	9/27/79
II.H	TMI-2 CLEANUP AND EXAMINATION						
II.H.2	Obtain Technical Data on the Conditions Inside the TMI-2 Containment Structure	HIGH	NA	B&W		5/-/80	NA
II.J	GENERAL IMPLICATIONS OF TMI FOR DESIGN AND CONSTRUCTION ACTIVITIES						
~~II.J.4~~	~~Revise Deficiency Reporting Requirements~~						
II.J.4.1	Revise Deficiency Reporting Requirements	NOTE 2	All	All		TBD	TBD
II.K	MEASURES TO MITIGATE SMALL-BREAK LOSS-OF-COOLANT ACCIDENTS AND LOSS-OF-FEEDWATER ACCIDENTS						
II.K.1	IE Bulletins	-					
II.K.1(1)	Review TMI-2 PNs and Detailed Chronology of the TMI-2 Accident	NOTE 3(a)	All	All		3/31/80	NA
II.K.1(2)	Review Transients Similar to TMI-2 That Have Occurred at Other Facilities and NRC Evaluation of Davis-Besse Event	NOTE 3(a)	NA	B&W		3/31/80	NA
II.K.1(3)	Review Operating Procedures for Recognizing, Preventing, and Mitigating Void Formation in Transients and Accidents	NOTE 3(a)	NA	All		3/31/80	NA
II.K.1(4)	Review Operating Procedures and Training Instructions	NOTE 3(a)	All	All		3/31/80	NA
II.K.1(5)	Safety-Related Valve Position Description	NOTE 3(a)	All	All		3/31/80	3/31/80
II.K.1(6)	Review Containment Isolation Initiation Design and Procedures	NOTE 3(a)	All	All		3/31/80	NA
II.K.1(7)	Implement Positive Position Controls on Valves That Could Compromise or Defeat AFW Flow	NOTE 3(a)	NA	B&W		3/31/80	NA
II.K.1(8)	Implement Procedures That Assure Two Independent 100% AFW Flow Paths	NOTE 3(a)	NA	B&W		3/31/80	NA
II.K.1(9)	Review Procedures to Assure That Radioactive Liquids and Gases Are Not Transferred out of Containment Inadvertently	NOTE 3(a)	All	All		3/31/80	NA
II.K.1(10)	Review and Modify Procedures for Removing Safety-Related Systems from Service	NOTE 3(a)	All	All		3/31/80	3/31/80
II.K.1(11)	Make All Operating and Maintenance Personnel Aware of the Seriousness and Consequences of the Erroneous Actions Leading up to, and in Early Phases of, the TMI-2 Accident	NOTE 3(a)	All	All		3/31/80	NA

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	Affected NSSS Vendor PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
II.K.1(12)	One Hour Notification Requirement and Continuous Communications Channels	NOTE 3(a)	All	All			NA
II.K.1(13)	Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items	NOTE 3(a)	All	All		1/1/81	1/1/81
II.K.1(14)	Review Operating Modes and Procedures to Deal with Significant Amounts of Hydrogen	NOTE 3(a)	GE	CE, W		3/31/80	NA
II.K.1(15)	For Facilities with Non-Automatic AFW Initiation, Provide Dedicated Operator in Continuous Communication with CR to Operate AFW	NOTE 3(a)	NA	CE, W			NA
II.K.1(16)	Implement Procedures That Identify PRZ PORV "Open" Indications and That Direct Operator to Close Manually at "Reset" Setpoint	NOTE 3(a)	NA	CE, W			NA
II.K.1(17)	Trip PZR Level Bistable so That PZR Low Pressure Will Initiate Safety Injection	NOTE 3(a)	NA	W			
II.K.1(18)	Develop Procedures and Train Operators on Methods of Establishing and Maintaining Natural Circulation	NOTE 3(a)	NA	B&W			NA
II.K.1(19)	Describe Design and Procedure Modifications to Reduce Likelihood of Automatic PZR PORV Actuation in Transients	NOTE 3(a)	NA	B&W		3/31/80	NA
II.K.1(20)	Provide Procedures and Training to Operators for Prompt Manual Reactor Trip for LOFW, TT, MSIV Closure, LOOP, LOSG Level, and LO PZR Level	NOTE 3(a)	NA	B&W		3/31/80	3/31/80
II.K.1(21)	Provide Automatic Safety-Grade Anticipatory Reactor Trip for LOFW, TT, or Significant Decrease in SG Level	NOTE 3(a)	NA	B&W		3/31/80	3/31/80
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When FW System Not Operable	NOTE 3(a)	All	NA		3/31/80	3/31/80
II.K.1(23)	Describe Uses and Types of RV Level Indication for Automatic and Manual Initiation Safety Systems	NOTE 3(a)	All	NA		3/31/80	3/31/80
II.K.1(24)	Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and RCP Trip	NOTE 3(a)	NA	All		NA	
II.K.1(25)	Develop Operator Action Guidelines	NOTE 3(a)	NA	All		NA	
II.K.1(26)	Revise Emergency Procedures and Train ROs and SROs	NOTE 3(a)	NA	All		NA	
II.K.1(27)	Provide Analyses and Develop Guidelines and Procedures for Inadequate Core Cooling Conditions	NOTE 3(a)	NA	All		NA	
II.K.1(28)	Provide Design That Will Assure Automatic RCP Trip for All Circumstances Where Required	NOTE 3(a)	NA	All		1/1/81	1/1/82
II.K.2	Commission Orders on B&W Plants	-					
II.K.2(1)	Upgrade Timeliness and Reliability of AFW System	NOTE 3(a)	NA	B&W		NA	
II.K.2(2)	Procedures and Training to Initiate and Control AFW Independent of Integrated Control System	NOTE 3(a)	NA	B&W		NA	
II.K.2(3)	Hard-Wired Control-Grade Anticipatory Reactor Trips	NOTE 3(a)	NA	B&W		NA	
II.K.2(4)	Small-Break LOCA Analysis, Procedures and Operator Training	NOTE 3(a)	NA	B&W		NA	
II.K.2(5)	Complete TMI-2 Simulator Training for All Operators	NOTE 3(a)	NA	B&W		NA	

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
II.K.2(6)	Reevaluate Analysis for Dual-Level Setpoint Control	NOTE 3(a)	NA	B&W		NA	
II.K.2(7)	Reevaluate Transient of September 24, 1977	NOTE 3(a)	NA	B&W		NA	
II.K.2(9)	Analysis and Upgrading of Integrated Control System	I	NA	B&W	F-27	1/1/81	1/1/81
II.K.2(10)	Hard-Wired Safety-Grade Anticipatory Reactor Trips	I	NA	B&W	F-28	1/1/81	1/1/81
II.K.2(11)	Operator Training and Drilling	I	NA	B&W	F-29	1/1/81	1/1/81
II.K.2(13)	Thermal-Mechanical Report on Effect of HPI on Vessel Integrity for Small-Break LOCA With No AFW	I	NA	B&W	F-30	1/1/81	1/1/81
II.K.2(14)	Demonstrate That Predicted Lift Frequency of PORVs and SVs Is Acceptable	I	NA	-	F-31	1/1/81	1/1/81
II.K.2(15)	Analysis of Effects of Slug Flow on Once-Through Steam Generator Tubes After Primary System Voiding	I	NA	B&W		6/1/80	6/1/80
II.K.2(16)	Impact of RCP Seal Damage Following Small-Break LOCA With Loss of Offsite Power	I	NA	B&W	F-32	6/1/80	6/1/80
II.K.2(17)	Analysis of Potential Voiding in RCS During Anticipated Transients	I	NA	B&W	F-33		NA
II.K.2(19)	Benchmark Analysis of Sequential AFW Flow to Once-Through Steam Generator	I	NA	B&W	F-34	1/1/81	NA
II.K.2(20)	Analysis of Steam Response to Small-Break LOCA That Causes System Pressure to Exceed PORV Setpoint	I	NA	B&W	F-35	1/1/81	NA
II.K.2(21)	LOFT L3-1 Predictions	NOTE 3(a)	NA	B&W			NA
II.K.3	Final Recommendations of Bulletins and Orders Task Force	-					
II.K.3(1)	Install Automatic PORV Isolation System and Perform Operational Test	I	NA	All	F-36	7/1/81	7/1/81
II.K.3(2)	Report on Overall Safety Effect of PORV Isolation System	I	NA	All	F-37	1/1/81	1/1/81
II.K.3(3)	Report Safety and Relief Valve Failures Promptly and Challenges Annually	I	All	All	F-38	4/1/80	4/1/80
II.K.3(5)	Automatic Trip of Reactor Coolant Pumps	I	NA	All	F-39, G-01	1/1/81	1/1/81
II.K.3(7)	Evaluation of PORV Opening Probability During Overpressure Transient	I	NA	B&W		1/1/81	1/1/81
II.K.3(9)	Proportional Integral Derivative Controller Modification	I	NA	W	F-40	7/1/80	7/1/80
II.K.3(10)	Anticipatory Trip Modification Proposed by Some Licensees to Confine Range of Use to High Power Levels	I	NA	W	F-41		
II.K.3(11)	Control Use of PORV Supplied by Control Components, Inc. Until Further Review Complete	I	All	All			
II.K.3(12)	Confirm Existence of Anticipatory Trip Upon Turbine Trip	I	NA	W	F-42	7/1/80	7/1/80
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	I	GE	NA	F-43	10/1/80	10/1/80
II.K.3(14)	Isolation of Isolation Condensers on High Radiation	I	GE	NA	F-44	1/1/81	NA
II.K.3(15)	Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems	I	GE	NA	F-45	1/1/81	1/1/81
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification	I	GE	NA	F-46	1/1/81	1/1/81
II.K.3(17)	Report on Outage of ECC Systems - Licensee Report and Technical Specification Changes	I	GE	NA	F-47	1/1/81	1/1/81

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
II.K.3(18)	Modification of ADS Logic - Feasibility Study and Modification for Increased Diversity for Some Event Sequences	I	GE	NA	F-48	1/1/81	1/1/81
II.K.3(19)	Interlock on Recirculation Pump Loops	I	GE	NA	F-49	1/1/81	NA
II.K.3(20)	Loss of Service Water for Big Rock Point	I	GE	NA		1/1/81	NA
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level - Design and Modification	I	GE	NA	F-50	1/1/81	1/1/81
II.K.3(22)	Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design	I	GE	NA	F-51	1/1/81	1/1/81
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	I	GE	NA	F-52	1/1/82	1/1/82
II.K.3(25)	Effect of Loss of AC Power on Pump Seals	I	GE	NA	F-53	1/1/82	1/1/82
II.K.3(27)	Provide Common Reference Level for Vessel Level Instrumentation	I	GE	NA	F-54	10/1/80	10/1/80
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	I	GE	NA	F-55	1/1/82	1/1/82
II.K.3(29)	Study to Demonstrate Performance of Isolation Condensers with Non-Condensibles	I	GE	NA	F-56	4/1/81	NA
II.K.3(30)	Revised Small-Break LOCA Methods to Show Compliance with 10 CFR 50, Appendix K	I	All	All	F-57	1/1/83	1/1/83
II.K.3(31)	Plant-Specific Calculations to Show Compliance with 10 CFR 50.46	I	All	All	F-58	1/1/83	1/1/83
II.K.3(44)	Evaluation of Anticipated Transients with Single Failure to Verify No Significant Fuel Failure	I	GE	NA	F-59	1/1/81	1/1/81
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	I	GE	NA	F-60	1/1/81	1/1/81
II.K.3(46)	Response to List of Concerns from ACRS Consultant	I	GE	NA	F-61	7/1/80	7/1/80
II.K.3(57)	Identify Water Sources Prior to Manual Activation of ADS	I	GE	NA	F-62	10/1/80	NA
III.A	EMERGENCY PREPAREDNESS AND RADIATION EFFECTS						
III.A.1	Improve Licensee Emergency Preparedness - Short Term						
III.A.1.1	Upgrade Emergency Preparedness	-					
III.A.1.1(1)	Implement Action Plan Requirements for Promptly Improving Licensee Emergency Preparedness	I	All	All		10/10/79	8/19/80
III.A.1.1(2)	Perform an Integrated Assessment of the Implementation	I	All	All		10/10/79	8/19/80
III.A.1.2	Upgrade Licensee Emergency Support Facilities	-					
III.A.1.2(1)	Technical Support Center	I	All	All	F-63	9/13/79	9/27/79
III.A.1.2(2)	On-Site Operational Support Center	I	All	All	F-64	9/13/79	9/27/79
III.A.1.2(3)	Near-Site Emergency Operations Facility	I	All	All	F-65	9/13/79	9/27/79
III.A.2	Improving Licensee Emergency Preparedness-Long Term						
III.A.2.1	Amend 10 CFR 50 and 10 CFR 50, Appendix E	-					
III.A.2.1(1)	Publish Proposed Amendments to the Rules	I	All	All			
III.A.2.1(2)	Conduct Public Regional Meetings	I	All	All			

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	Affected NSSS Vendor PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
III.A.2.1(3)	Prepare Final Commission Paper Recommending Adoption of Rules	I	All	All			
III.A.2.1(4)	Revise Inspection Program to Cover Upgraded Requirements	I	All	All	F-67		
III.A.2.2	Development of Guidance and Criteria	I	All	All	F-68		
III.A.3	Improving NRC Emergency Preparedness						
III.A.3.3	Communications	-					
III.A.3.3(1)	Install Direct Dedicated Telephone Lines	NOTE 3(a)	All	All			
III.A.3.3(2)	Obtain Dedicated, Short-Range Radio Communication Systems	NOTE 3(a)	All	All			
III.D	RADIATION PROTECTION						
III.D.1	Radiation Source Control						
III.D.1.1	Primary Coolant Sources Outside the Containment Structure	-					
III.D.1.1(1)	Review Information Submitted by Licensees Pertaining to Reducing Leakage from Operating Systems	I	All	All		7/2/79	9/27/79
III.D.3	Worker Radiation Protection Improvement						
III.D.3.3	Inplant Radiation Monitoring	-					
III.D.3.3(1)	Issue Letter Requiring Improved Radiation Sampling Instrumentation	I	All	All	F-69	9/13/79	9/27/79
III.D.3.3(2)	Set Criteria Requiring Licensees to Evaluate Need for Additional Survey Equipment	NOTE 3(a)	All	All		9/13/79	9/27/79
III.D.3.3(3)	Issue a Rule Change Providing Acceptable Methods for Calibration of Radiation-Monitoring Instruments	NOTE 3(a)	All	All		9/13/79	9/27/79
III.D.3.3(4)	Issue a Regulatory Guide	NOTE 3(a)	All	All		9/13/79	9/27/79
III.D.3.4	Control Room Habitability	I	All	All	F-70	5/7/80	6/26/80

TASK ACTION PLAN ITEMS

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	Affected NSSS Vendor PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
A-1	Water Hammer (former USI)	NOTE 3(a)	All	All		NA	3/15/84
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems (former USI)	NOTE 3(a)	NA	All	D-10	1/-/81	1/-/81
A-3	Westinghouse Steam Generator Tube Integrity (former USI)	NOTE 3(a)	NA	W		4/17/85	4/17/85
A-4	CE Steam Generator Tube Integrity (former USI)	NOTE 3(a)	NA	CE		4/17/85	4/17/85
A-5	B&W Steam Generator Tube Integrity (former USI)	NOTE 3(a)	NA	B&W		4/17/85	4/17/85
A-6	Mark I Short-Term Program (former USI)	NOTE 3(a)	GE	NA		12/-/77	NA
A-7	Mark I Long-Term Program (former USI)	NOTE 3(a)	GE	NA	D-01	8/-/82	8/-/82
A-8	Mark II Containment Pool Dyanmic Loads - Long Term Program (former USI)	NOTE 3(a)	GE	NA		8/-/81	8/-/81
A-9	ATWS (former USI)	NOTE 3(a)	All	All		6/26/84	6/26/84
A-10	BWR Feedwater Nozzle Cracking (former USI)	NOTE 3(a)	All	NA	B-25	11/-/80	11/-/80

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
A-11	Reactor Vessel Materials Toughness (former USI)	NOTE 3(a)	All	All		10/-/82	NA
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (former USI)	NOTE 3(a)	NA	All		NA	TBD
A-13	Snubber Operability Assurance	NOTE 3(a)	All	All		1980	1981
A-16	Steam Effects on BWR Core Spray Distribution	NOTE 3(a)	GE	NA	D-12		NA
A-17	Systems Interaction	USI	All	All		TBD	TBD
A-19	Digital Computer Protection System	NOTE 4	All	All		TBD	TBD
A-24	Qualification of Class 1E Safety Related Equipment (former USI)	NOTE 3(a)	All	All	B-60	8/-/81	8/-/81
A-25	Non-Safety Loads on Class 1E Power Sources	NOTE 3(a)	All	All			9/-/78
A-26	Reactor Vessel Pressure Transient Protection (former USI)	NOTE 3(a)	NA	All	B-04	9/-/78	9/-/78
A-28	Increase in Spent Fuel Pool Storage Capacity	NOTE 3(a)	All	All		4/17/78	NA
A-29	Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage	MEDIUM	All	All		TBD	TBD
A-31	RHR Shutdown Requirements (former USI)	NOTE 3(a)	All	All		5/-/78	1/1/79
A-35	Adequacy of Offsite Power Systems	NOTE 3(a)	All	All		6/2/77	1981
A-36	Control of Heavy Loads Near Spent Fuel (former USI)	NOTE 3(a)	All	All	C-10, C-15	7/-/80	7/-/80
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits (former USI)	NOTE 3(a)	GE	NA		2/29/80	9/30/82
A-40	Seismic Design Criteria - Short Term Program	USI	All	All		TBD	TBD
A-42	Pipe Cracks in Boiling Water Reactors (former USI)	NOTE 3(a)	All	NA	B-05	2/-/81	2/-/81
A-43	Containment Emergency Sump Performance (former USI)	NOTE 3(a)	NA	All		TBD	TBD
A-44	Station Blackout (former USI)	NOTE 3(a)	All	All		TBD	TBD
A-46	Seismic Qualification of Equipment in Operating Plants (former USI)	NOTE 3(a)	All	All		TBD	NA
A-47	Safety Implications of Control Systems	USI	All	All		TBD	TBD
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	NOTE 3(a)	All	W			
A-49	Pressurized Thermal Shock (former USI)	NOTE 3(a)	NA	All	A-21	TBD	TBD
B-10	Behavior of BWR Mark III Containments	NOTE 3(a)	GE	NA			9/-/84
B-17	Criteria for Safety-Related Operator Actions	MEDIUM	All	All		TBD	TBD
B-22	LWR Fuel	NOTE 4	All	All		TBD	TBD
B-29	Effectiveness of Ultimate Heat Sinks	NOTE 4	All	All		TBD	TBD
B-32	Ice Effects on Safety-Related Water Supplies	NOTE 4	All	All		TBD	TBD
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and for Normal Ventilation Systems	NOTE 3(a)	All	All			3/-/78
B-55	Improved Reliability of Target Rock Safety Relief Valves	MEDIUM	All	NA		TBD	TBD
B-56	Diesel Reliability	HIGH	All	All	D-19	TBD	TBD
B-61	Allowable ECCS Equipment Outage Periods	MEDIUM	All	All		TBD	TBD
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	NOTE 3(a)	All	All		4/20/81	

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
B-64	Decommissioning of Reactors	NOTE 2	All	All		TBD	NA
B-66	Control Room Infiltration Measurements	NOTE 3(a)	All	All		NA	7/-/81
B-70	Power Grid Frequency Degradation and Effect on Primary Coolant Pumps	NOTE 3(a)	All	All		NA	7/-/81
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	NOTE 3(a)	All	All		5/27/80	5/27/80
C-8	Main Steam Line Leakage Control Systems	HIGH	All	NA		TBD	TBD
C-10	Effective Operation of Containment Sprays in a LOCA	NOTE 3(a)	All	All		NA	
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	NOTE 3(a)	All	All		12/27/82	12/27/82

NEW GENERIC ISSUES

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
2.	Failure of Protective Devices on Essential Equipment	NOTE 4	All	All		TBD	TBD
15.	Radiation Effects on Reactor Vessel Supports	HIGH	All	All		TBD	TBD
23.	Reactor Coolant Pump Seal Failures	HIGH	All	All		TBD	TBD
24.	Automatic Emergency Core Cooling System Switch to Recirculation	NOTE 4	All	All		TBD	TBD
25.	Automatic Air Header Dump on BWR Scram System	NOTE 3(a)	All	NA		1/9/81	1/9/81
29.	Bolting Degradation or Failure in Nuclear Power Plants	HIGH	All	All		TBD	TBD
38.	Potential Recirculation System Failure as a Consequence of Injection of Containment Paint Flakes or Other Fine Debris	NOTE 4	All	All		TBD	TBD
40.	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	NOTE 3(a)	All	NA	B-65	8/31/81	8/31/81
41.	BWR Scram Discharge Volume Systems	NOTE 3(a)	All	NA	B-58	12/9/80	NA
43.	Reliability of Air Systems	NOTE 3(a)	All	All		8/8/88	NA
45.	Inoperability of Instrumentation Due to Extreme Cold Weather	NOTE 3(a)	All	All		NA	9/1/83
51.	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems	MEDIUM	All	All		TBD	TBD
57.	Effects of Fire Protection System Actuation on Safety-Related Equipment	MEDIUM	All	All		TBD	TBD
63.	Use of Equipment Not Classified as Essential to Safety in BWR Transient Analysis	NOTE 4	All	NA		TBD	TBD
67.	Steam Generator Staff Actions	-	-	-		-	-
67.3.3	Improved Accident Monitoring	NOTE 3(a)	All	All	A-17	12/17/82	12/17/82
70.	PORV and Block Valve Reliability	MEDIUM	NA	All		TBD	TBD
71.	Failure of Resin Demineralizer Systems and Their Effects on Nuclear Power Plant Safety	NOTE 4	All	All		TBD	TBD
72.	Control Rod Drive Guide Tube Support Pin Failures	NOTE 4	NA	W		TBD	TBD
73.	Detached Thermal Sleeves	NOTE 4	All	All		TBD	TBD

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants- Effective Date	Future Plants- Effective Date
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	NOTE 1	All	All	B-76, B-77, B-78, B-79, B-80, B-81, B-82, B-85, B-86, B-87, B-88, B-89, B-90, B-91, B-92, B-93	TBD	TBD
76.	Instrumentation and Control Power Interactions	NOTE 4	All	All		TBD	TBD
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	NOTE 4	All	All		TBD	TBD
79.	Unanalyzed Reactor Vessel Thermal Stress During Natural Convection Cooldown	MEDIUM	NA	B&W		TBD	TBD
83.	Control Room Habitability	NOTE 1	All	All		TBD	TBD
84.	CE PORVs	NOTE 1	NA	CE		TBD	TBD
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	NOTE 3(a)	All	NA	B-84	TBD	TBD
87.	Failure of HPCI Steam Line Without Isolation	HIGH	All	All		TBD	TBD
89.	Stiff Pipe Clamps	NOTE 4	All	All		TBD	TBD
93.	Steam Binding of Auxiliary Feedwater Pumps	NOTE 3(a)	NA	All		TBD	TBD
94.	Additional Low Temperature Overpressure Protection Issues for Light Water Reactors	HIGH	NA	All		TBD	TBD
95.	Loss of Effective Volume for Containment Recirculation Spray	NOTE 4	All	All		TBD	TBD
96.	RHR Suction Valve Testing	NOTE 4	All	All		TBD	TBD
99.	RCS/RHR Suction Line Valve Interlock on PWRs	NOTE 3(a)	NA	All		10/17/88	NA
100.	OTSG Level	NOTE 4	NA	B&W		TBD	TBD
103.	Design for Probable Maximum Precipitation	NOTE 1	All	All		TBD	TBD
105.	Interfacing Systems LOCA at BWRs	HIGH	All	NA		TBD	TBD
106.	Piping and Use of Highly Combustible Gases in Vital Areas	MEDIUM	All	All		TBD	TBD
107.	Generic Implications of Main Transformer Failures	NOTE 4	All	All		TBD	TBD
109.	Reactor Vessel Closure Failure	NOTE 4	All	All		TBD	TBD
110.	Equipment Protective Devices on Engineered Safety Features	NOTE 4	All	All		TBD	TBD
113.	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers	HIGH	All	All		TBD	TBD
116.	Accident Management	NOTE 4	All	All		TBD	TBD
117.	Allowable Outage Times for Diverse Simultaneous Equipment Outages	NOTE 4	All	All		TBD	TBD
118.	Tendon Anchorage Failure	NOTE 4	All	All		TBD	TBD
120.	On-Line Testability of Protection Systems	NOTE 4	All	All		TBD	TBD
121.	Hydrogen Control for Large, Dry PWR Containments	HIGH	All	All		TBD	TBD
123.	Deficiencies in the Regulations Governing DBA and Single-Failure Criteria Suggested by the Davis-Besse Event of June 9, 1985	NOTE 4	All	All		TBD	TBD
124.	Auxiliary Feedwater System Reliability	NOTE 3(a)	All	All		TBD	TBD

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	Affected NSSS Vendor PWR	Operating Plants MPA No.	Operating Plants-Effective Date	Future Plants-Effective Date
125.	Davis-Besse Loss of All Feedwater Event of June 9, 1985: Long-Term Actions	-	All	All		TBD	TBD
125.I.3	SPDS Availability	NOTE 3(a)	All	All		TBD	TBD
128.	Electrical Power Reliability	HIGH	All	All		TBD	TBD
129.	Valve Interlocks to Prevent Vessel Drainage During Shutdown Cooling	NOTE 4	All	All		TBD	TBD
130.	Essential Service Water Pump Failures at Multiplant Sites	HIGH	All	All		TBD	TBD
131.	Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System in Westinghouse Plants	NOTE 4	NA	W		TBD	TBD
132.	RHR Pumps Inside Containment	NOTE 4	All	All		TBD	TBD
134.	Rule on Degree and Experience Requirement	HIGH	All	All		TBD	TBD
135.	Integrated Steam Generator Issues	MEDIUM	All	All		TBD	TBD
137.	Refueling Cavity Seal Failure	NOTE 4	All	All		TBD	TBD
138.	Deintering Upon Discovery of RCS Leakage	NOTE 4	All	All		TBD	TBD
140.	Fission Product Removal by Containment Sprays	NOTE 4	All	All		TBD	TBD
141.	LBLOCA with Consequential SGTR	NOTE 4	All	All		TBD	TBD
142.	Leakage Through Electrical Isolators	NOTE 4	All	All		TBD	TBD
143.	Availability of Chilled Water Systems	NOTE 4	All	All		TBD	TBD
144.	Scram Without a Turbine/Generator Trip	NOTE 4	All	All		TBD	TBD
145.	Improve Surveillance and Startup Testing Programs	NOTE 4	All	All		TBD	TBD
146.	Support Flexibility of Equipment and Components	NOTE 4	All	All		TBD	TBD
147.	Fire-Induced Alternate Shutdown Control Room Panel Interactions	NOTE 4	All	All		TBD	TBD
148.	Smoke Control and Manual Fire-Fighting Effectiveness	NOTE 4	All	All		TBD	TBD
149.	Adequacy of Fire Barriers	NOTE 4	All	All		TBD	TBD
150.	Overpressurization of Containment Penetrations	NOTE 4	All	All		TBD	TBD
151.	Reliability of Recirculation Pump Trip During an ATWS	NOTE 4	All	All		TBD	TBD
	HUMAN FACTORS ISSUES						
HF1	STAFFING AND QUALIFICATIONS						
HF.1.1	Shift Staffing	NOTE 3(a)	All	All		TBD	TBD
HF4	PROCEDURES						
HF4.4	Guidelines for Upgrading Other Procedures	HIGH	All	All		TBD	TBD
HF5	MAN-MACHINE INTERFACE						
HF5.1	Local Control Stations	HIGH	All	All		TBD	TBD
HF5.2	Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation	HIGH	All	All		TBD	TBD

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

The report presents the priority rankings for generic safety issues related to nuclear power plants. The purpose of these rankings is to assist in the timely and efficient allocation of NRC resources for the resolution of those safety issues that have a significant potential for reducing risk. The safety priority rankings are HIGH, MEDIUM, LOW, and DROP and have been assigned on the basis of risk significance estimates, the ratio of risk to costs and other impacts estimated to result if resolutions of the safety issues were implemented, and the consideration of uncertainties and other quantitative or qualitative factors. To the extent practical, estimates are quantitative.

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