UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

February 1986

SUPPLEMENT 4 TO NUREG-0933
"A PRIORITIZATION OF GENERIC SAFETY ISSUES"
REVISION INSERTION INSTRUCTIONS

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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 multi-plant 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
E	- Environmental Issue
HFPP	- Human Factors Program Plan
I	- TMI Action Plan Item With Implementation of Resolution Mandated by NUREG-0737[98]
LI	- Licensing Issue
MPA	- Multi-Plant Action (See Status in NUREG-0748)[578]
NA	- Not Applicable
RI	- Regulatory Impact Issue
USI	- Unresolved Safety Issue (See Status in NUREG-0606)[60]

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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			F-01
I.A.1.2	Shift Supervisor Administrative Duties	-	NRR/DHFS/LQB	I			
I.A.1.3	Shift Manning	-	NRR/DHFS/LQB	I			F-02
I.A.1.4	Long-Term Upgrading	Colmar	RES/DFO/HFBR	NOTE 3(a)	1	6/30/84	
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	3	12/31/85	F-03
I.A.2.1(2)	Training	-	NRR/DHFS/LQB	I	3	12/31/85	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	3	12/31/85	F-03
I.A.2.2	Training and Qualifications of Operations Personnel	Colmar	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/85	NA
I.A.2.3	Administration of Training Programs	-	NRR/DHFS/LQB	I	3	12/31/85	
I.A.2.4	NRR Participation in Inspector Training	Colmar	NRR/DHFS/LQB	LI (NOTE 5)	3	12/31/85	NA
I.A.2.5	Plant Drills	Colmar	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/85	NA
I.A.2.6	Long-Term Upgrading of Training and Qualifications	-	-	-			
I.A.2.6(1)	Revise Regulatory Guide 1.8	Colmar	NRR/DHFS/LQB	HF01.1.2	3	12/31/85	NA
I.A.2.6(2)	Staff Review of NRR 80-117	Colmar	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/85	NA
I.A.2.6(3)	Revise 10 CFR 55	Colmar	NRR/DHFS/LQB	I.A.2.2	3	12/31/85	NA
I.A.2.6(4)	Operator Workshops	Colmar	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/85	NA
I.A.2.6(5)	Develop Inspection Procedures for Training Program	Colmar	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/85	NA
I.A.2.6(6)	Nuclear Power Fundamentals	Colmar	NRR/DHFS/LQB	DROP	3	12/31/85	NA
I.A.2.7	Accreditation of Training Institutions	Colmar	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/85	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	4	12/31/85	
I.A.3.2	Operator Licensing Program Changes	Emrit	NRR/DHFS/OLB	NOTE 3(b)	4	12/31/85	NA
I.A.3.3	Requirements for Operator Fitness	Colmar	RES/DRAO/HFSB	HIGH	4	12/31/85	
I.A.3.4	Licensing of Additional Operations Personnel	Thatcher	NRR/DHFS/LQB	NOTE 3(b)	4	12/31/85	NA
I.A.3.5	Establish Statement of Understanding with INPO and DOE	Thatcher	NRR/DHFS/HFEB	LI (NOTE 3)	4	12/31/85	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)	2	12/31/85	NA
I.A.4.1(2)	Interim Changes in Training Simulators	Thatcher	NRR/DHFS/OLB	NOTE 3(a)	2	12/31/85	
I.A.4.2	Long-Term Training Simulator Upgrade	-	-	-			
I.A.4.2(1)	Research on Training Simulators	Colmar	NRR/DHFS/OLB	HIGH	2	12/31/85	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
I.A.4.2(2)	Upgrade Training Simulator Standards	Colmar	RES/DFO/HFBR	NOTE 3(a)	2	12/31/85	
I.A.4.2(3)	Regulatory Guide on Training Simulators	Colmar	RES/DFO/HFBR	NOTE 3(a)	2	12/31/85	
I.A.4.2(4)	Review Simulators for Conformance to Criteria	Colmar	NRR/DHFS/OLB	HF01.3.3	2	12/31/85	NA
I.A.4.3	Feasibility Study of Procurement of NRC Training Simulator	Colmar	RES/DAE/RSRB	LI (NOTE 3)	2	12/31/85	NA
I.A.4.4	Feasibility Study of NRC Engineering Computer	Colmar	RES/DAE/RSRB	LI (NOTE 5)	2	12/31/85	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/DHFS/LQB	HF01.6.1, HF01.6.3	2	12/31/85	NA
I.B.1.1(2)	Prepare Commission Paper	Colmar	NRR/DHFS/LQB	HF01.6.1, HF01.6.3	2	12/31/85	NA
I.B.1.1(3)	Issue Requirements for the Upgrading of Management and Technical Resources	Colmar	NRR/DHFS/LQB	HF01.6.1, HF01.6.3	2	12/31/85	NA
I.B.1.1(4)	Review Responses to Determine Acceptability	Colmar	NRR/DHFS/LQB	HF01.6.1, HF01.6.3	2	12/31/85	NA
I.B.1.1(5)	Review Implementation of the Upgrading Activities	Colmar	OIE/DQASIP/ORPB	NOTE 3(b)	2	12/31/85	NA
I.B.1.1(6)	Prepare Revisions to Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	HF01.1.2, HF01.3.4, 75	2	12/31/85	NA
I.B.1.1(7)	Issue Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	HF01.1.2, HF01.3.4, 75	2	12/31/85	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	I			
I.B.1.2(2)	Review Near-Term Operating License Facilities	-	NRR/DHFS/LQB	I			
I.B.1.2(3)	Include Findings in the SER for Each Near-Term Operating License Facility	-	NRR/DL/ORAB	I			
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)	2	12/31/85	NA
I.B.1.3(2)	Use Existing Enforcement Options to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	2	12/31/85	NA
I.B.1.3(3)	Use Non-Fiscal Approaches to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	2	12/31/85	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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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
I.C	OPERATING PROCEDURES						
I.C.1	Short-Term Accident Analysis and Procedures Revision	-	-	-			
I.C.1(1)	Small Break LOCAs	-	NRR	I			
I.C.1(2)	Inadequate Core Cooling	-	NRR	I			F-04
I.C.1(3)	Transients and Accidents	-	NRR	I			F-05
I.C.1(4)	Confirmatory Analyses of Selected Transients	Riggs	NRR/DSI/RSB	NOTE 3(b)	2	12/31/85	NA
I.C.2	Shift and Relief Turnover Procedures	-	NRR	I			
I.C.3	Shift Supervisor Responsibilities	-	NRR	I			
I.C.4	Control Room Access	-	NRR	I			
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	-	NRR/DL	I			F-06
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	-	NRR/DL	I			F-07
I.C.7	NSSS Vendor Review of Procedures	-	NRR/DHFS/PSRB	I			
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	-	NRR/DHFS/PSRB	I			
I.C.9	Long-Term Program Plan for Upgrading of Procedures	Riggs	NRR/DHFS/PSRB	HF01.4.2, HF01.4.4, HF02	2	12/31/85	NA
I.D	CONTROL ROOM DESIGN						
I.D.1	Control Room Design Reviews	-	NRR/DL	I			F-08
I.D.2	Plant Safety Parameter Display Console	-	NRR/DL	I			F-09
I.D.3	Safety System Status Monitoring	Thatcher	NRR/DHFS/HFEB	MEDIUM	2	12/31/85	
I.D.4	Control Room Design Standard	Thatcher	NRR/DHFS/HFEB	HF01.5.3	2	12/31/85	NA
I.D.5	Improved Control Room Instrumentation Research	-	-	-			
I.D.5(1)	Operator-Process Communication	Thatcher	RES/DFO/HFBR	NOTE 3(b)	2	12/31/85	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
I.D.5(2)	Plant Status and Post-Accident Monitoring	Thatcher	RES/DFO/HFBR	NOTE 3(a)	2	12/31/85	
I.D.5(3)	On-Line Reactor Surveillance System	Thatcher	RES/DET/EEIGB	NOTE 1	2	12/31/85	
I.D.5(4)	Process Monitoring Instrumentation	Thatcher	RES/DFO/ICBR	NOTE 3(b)	2	12/31/85	NA
I.D.5(5)	Disturbance Analysis Systems	Thatcher	NRR/DHFS/HFEB	HF01.5.4	2	12/31/85	NA
I.D.6	Technology Transfer Conference	Thatcher	RES/DFO/HFBR	LI (NOTE 3)	2	12/31/85	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	OIE/DQASIP/QUAB	HIGH	1	12/31/85	
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	1	12/31/85	NA
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	1	12/31/85	NA
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	1	12/31/85	NA
I.F.2(4)	Establish Criteria for Determining QA Requirements for Specific Classes of Equipment	Pittman	OIE/DQASIP/QUAB	LOW	1	12/31/85	NA
I.F.2(5)	Establish Qualification Requirements for QA and QC Personnel	Pittman	OIE/DQASIP/QUAB	LOW	1	12/31/85	NA
I.F.2(6)	Increase the Size of Licensees' QA Staff	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	1	12/31/85	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	1	12/31/85	NA
I.F.2(8)	Compare NRC QA Requirements with Those of Other Agencies	Pittman	OIE/DQASIP/QUAB	LOW	1	12/31/85	NA
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	1	12/31/85	NA
I.F.2(10)	Clarify Requirements for Maintenance of "As-Built" Documentation	Pittman	OIE/DQASIP/QUAB	LOW	1	12/31/85	NA
I.F.2(11)	Define Role of QA in Design and Analysis Activities	Pittman	OIE/DQASIP/QUAB	LOW	1	12/31/85	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
I.G	PREOPERATIONAL AND LOW-POWER TESTING						
I.G.1	Training Requirements	-	NRR/DHFS/PSRB	I			
I.G.2	Scope of Test Program	V'Molen	NRR/DHFS/PSRB	NOTE 3(a)	1	12/31/84	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			F-10
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	-	NRR/DL	I			F-11
II.B.3	Post-Accident Sampling	-	NRR/DL	I			F-12
II.B.4	Training for Mitigating Core Damage	-	NRR/DL	I			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/DAE/FSRB	HIGH	1	12/31/85	
II.B.5(2)	Behavior of Core Melt	V'Molen	RES/DAE/CSRB	HIGH	1	12/31/85	
II.B.5(3)	Effect of Hydrogen Burning and Explosions on Containment Structure	V'Molen	RES/DAE/CSRB	MEDIUM	1	12/31/85	
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	Pittman	NRR/DST/RRAB	NOTE 3(a)	1	12/31/85	
II.B.7	Analysis of Hydrogen Control	Matthews	NRR/DSI/CSB	II.B.8	1	12/31/85	
II.B.8	Rulemaking Proceeding on Degraded Core Accidents	V'Molen	RES/DRAO/RAMR	NOTE 3(a)	1	12/31/85	
II.C	RELIABILITY ENGINEERING AND RISK ASSESSMENT						
II.C.1	Interim Reliability Evaluation Program	Pittman	RES/DRAO/RRB	NOTE 3(b)	1	12/31/85	NA
II.C.2	Continuation of Interim Reliability Evaluation Program	Pittman	NRR/DST/RRAB	NOTE 3(b)	1	12/31/85	NA
II.C.3	Systems Interaction	Pittman	NRR/DST/GIB	A-17	1	12/31/85	NA
II.C.4	Reliability Engineering	Pittman	RES/DRAO/RRB	HIGH	1	12/31/85	
II.D	REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES						
II.D.1	Testing Requirements	-	NRR/DL	I			F-14
II.D.2	Research on Relief and Safety Valve Test Requirements	Riggs	RES	LOW		11/30/83	NA
II.D.3	Relief and Safety Valve Position Indication	-	NRR	I			

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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			F-15
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	-	NRR/DL	I			F-16, F-17
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	Riggs	RES/DRA/RRBR	NOTE 3(a)		11/30/83	
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			F-18
II.E.4.2	Isolation Dependability	-	NRR/DL	I			F-19
II.E.4.3	Integrity Check	Milstead	NRR/DSI/CSB	HIGH		11/30/83	
II.E.4.4	Purging	-	-	-			
II.E.4.4(1)	Issue Letter to Licensees Requesting Limited Purging	Milstead	NRR/DSI/CSB	NOTE 3(a)		11/30/83	
II.E.4.4(2)	Issue Letter to Licensees Requesting Information on Isolation Letter	Milstead	NRR/DSI/CSB	NOTE 3(a)		11/30/83	
II.E.4.4(3)	Issue Letter to Licensees on Valve Operability	Milstead	NRR/DSI/CSB	NOTE 3(a)		11/30/83	
II.E.4.4(4)	Evaluate Purging and Venting During Normal Operation	Milstead	NRR/DSI/CSB	NOTE 3(b)		11/30/83	NA
II.E.4.4(5)	Issue Modified Purging and Venting Requirement	Milstead	NRR/DSI/CSB	NOTE 3(b)		11/30/83	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	NRR/DE/MEB	MEDIUM		11/30/83	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.F	INSTRUMENTATION AND CONTROLS						
II.F.1	Additional Accident Monitoring Instrumentation	-	NRR/DL	I			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			F-26
II.F.3	Instruments for Monitoring Accident Conditions	V'Molen	RES/DFO/ICBR	NOTE 3(a)		11/30/83	
II.F.4	Study of Control and Protective Action Design Requirements	Thatcher	NRR/DSI/ICSB	DROP		11/30/83	NA
II.F.5	Classification of Instrumentation, Control, and Electrical Equipment	Thatcher	RES/DET/EEICB	MEDIUM		11/30/83	
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/DAE/FSRB	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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	OIE/DEPER/EAB	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	-

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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
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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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		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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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			
III.D.1.1(2)	Review Information on Provisions for Leak Detection	Emrit	NRR/DSI/METB	NOTE 4			
III.D.1.1(3)	Develop Proposed System Acceptance Criteria	Emrit	NRR/DSI/METB	NOTE 4			
III.D.1.2	Radioactive Gas Management	Emrit	NRR/DSI/METB	DROP		11/30/83	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		11/30/83	NA
III.D.1.3(2)	Review and Revise SRP	Emrit	NRR/DSI/METB	DROP		11/30/83	NA
III.D.1.3(3)	Require Licensees to Upgrade Filtration Systems	Emrit	NRR/DSI/METB	DROP		11/30/83	NA
III.D.1.3(4)	Sponsor Studies to Evaluate Charcoal Adsorber	Emrit	NRR/DSI/METB	NOTE 3(b)		11/30/83	NA
III.D.1.4	Radwaste System Design Features to Aid in Accident Recovery and Decontamination	Emrit	NRR/DSI/METB	DROP		11/30/83	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

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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
<u>III.D.3</u>	<u>Worker Radiation Protection Improvement</u>						
III.D.3.1	Radiation Protection Plans	V'Molen	NRR/DSI/RAB	HIGH		11/30/83	
III.D.3.2	Health Physics Improvements	-	-	-			
III.D.3.2(1)	Amend 10 CFR 20	V'Molen	RES/DFO/ORPBR	LI (NOTE 2)		11/30/83	NA
III.D.3.2(2)	Issue a Regulatory Guide	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)		11/30/83	NA
III.D.3.2(3)	Develop Standard Performance Criteria	V'Molen	RES/DFO/ORPBR	LI (NOTE 2)		11/30/83	NA
III.D.3.2(4)	Develop Method for Testing and Certifying Air-Purifying Respirators	V'Molen	RES/DFO/ORPBR	LI (NOTE 2)		11/30/83	NA
III.D.3.3	In-plant Radiation Monitoring	-	-	-			
III.D.3.3(1)	Issue Letter Requiring Improved Radiation Sampling Instrumentation	-	NRR/DL	I			F-69
III.D.3.3(2)	Set Criteria Requiring Licensees to Evaluate Need for Additional Survey Equipment	-	NRR	I			
III.D.3.3(3)	Issue a Rule Change Providing Acceptable Methods for Calibration of Radiation-Monitoring Instruments	-	RES	I			
III.D.3.3(4)	Issue a Regulatory Guide	-	RES	I			
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 5)		11/30/83	NA
III.D.3.5(2)	Investigative Methods of Obtaining Employee Health Data by Nonlegislative Means	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)		11/30/83	NA
III.D.3.5(3)	Revise 10 CFR 20	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)		11/30/83	NA

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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 5)	1	12/31/85	NA
IV.E.2	Plan for Early Resolution of Safety Issues	Emrit	NRR/DST/SPEB	LI (NOTE 3)	1	12/31/85	NA
IV.E.3	Plan for Resolving Issues at the CP Stage	Colmar	RES/DRA/RABR	LI (NOTE 2)	1	12/31/85	NA
IV.E.4	Resolve Generic Issues by Rulemaking	Colmar	RES/DRA/RABR	LI (NOTE 5)	1	12/31/85	NA
IV.E.5	Assess Currently Operating Reactors	Matthews	NRR/DL/SEPB	NOTE 3(b)	1	12/31/85	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)		11/30/83	NA
IV.F.2	Evaluate the Impacts of Financial Disincentives to the Safety of Nuclear Power Plants	Matthews	SP	NOTE 3(b)		11/30/83	NA

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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)		11/30/83	NA
IV.G.2	Periodic and Systematic Reevaluation of Existing Rules	Milstead	RES/DRA/RABR	LI (NOTE 5)		11/30/83	NA
IV.G.3	Improve Rulemaking Procedures	Milstead	RES/DRA/RABR	LI (NOTE 3)		11/30/83	NA
IV.G.4	Study Alternatives for Improved Rulemaking Process	Milstead	RES/DRA/RABR	LI (NOTE 3)		11/30/83	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

TASK ACTION PLAN ITEMS

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
A-1	Water Hammer	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	NA
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	D-10
A-3	Westinghouse Steam Generator Tube Integrity	-	NRR/DST/GIB	USI		11/30/83	
A-4	CE Steam Generator Tube Integrity	-	NRR/DST/GIB	USI		11/30/83	
A-5	B&W Steam Generator Tube Integrity	-	NRR/DST/GIB	USI		11/30/83	
A-6	Mark I Short-Term Program	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	
A-7	Mark I Long-Term Program	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	D-01
A-8	Mark II Containment Pool Dyanmic Loads Long-Term Program	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	NA
A-9	ATWS	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	
A-10	BWR Feedwater Nozzle Cracking	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	B-25
A-11	Reactor Vessel Materials Toughness	Emrit	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports	Emrit	NRR/DST/GIB	USI [NOTE 2]	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	-	NRR/DST/GIB	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

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	-	NRR/DST/GIB	USI [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	-	NRR/DST/GIB	USI [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	NRR/DSI/ASB	MEDIUM		11/30/83	
A-30	Adequacy of Safety-Related DC Power Supplies	Sege	NRR/DSI/PSB	HIGH		11/30/83	
A-31	RHR Shutdown Requirements	-	NRR/DST/GIB	USI [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	E(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	-	NRR/DSI/GIB	USI [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	-	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	
A-40	Seismic Design Criteria - Short Term Program	-	NRR/DST/GIB	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	-	NRR/DST/GIB	USI [NOTE 3(a)]	1	6/30/85	B-05
A-43	Containment Emergency Sump Performance	-	NRR/DST/GIB	USI		11/30/83	
A-44	Station Blackout	-	NRR/DST/GIB	USI		11/30/83	
A-45	Shutdown Decay Heat Removal Requirements	-	NRR/DST/GIB	USI		11/30/83	
A-46	Seismic Qualification of Equipment in Operating Plants	-	NRR/DST/GIB	USI		11/30/83	
A-47	Safety Implications of Control Systems	-	NRR/DST/GIB	USI		11/30/83	
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	-	NRR/DST/GIB	USI		11/30/83	
A-49	Pressurized Thermal Shock	-	NRR/DST/GIB	USI		11/30/83	
B-1	Environmental Technical Specifications	-	NRR/DE/EHEB	E (NOTE 3)		11/30/83	NA
B-2	Forecasting Electricity Demand	-	NRR	E (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	NRR/DE/SGEB	MEDIUM		11/30/83	
B-6	Loads, Load Combinations, Stress Limits	Pittman	NRR/DE/MEB	HIGH		11/30/83	
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

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
B-12	Containment Cooling Requirements (Non-LOCA)	Emrit	NRR/DSI/CSB	NOTE 3(a)		11/30/83	
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	NRR/DHFS/LQB	HF01.4.3	1	12/31/85	NA
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	E (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	NOTE 4		11/30/83	
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	E (NOTE 5)		11/30/83	
B-38	Reconnaissance Level Investigations	-	NRR/DE/EHEB	E (DROP)		11/30/83	NA
B-39	Transmission Lines	-	NRR/DE/EHEB	E (DROP)		11/30/83	NA
B-40	Effects of Power Plant Entrainment on Plankton	-	NRR/DE/EHEB	E (DROP)		11/30/83	NA
B-41	Impacts on Fisheries	-	NRR/DE/EHEB	E (DROP)		11/30/83	NA
B-42	Socioeconomic Environmental Impacts	-	NRR/DE/SAB	E (NOTE 3)		11/30/83	NA
B-43	Value of Aerial Photographs for Site Evaluation	-	NRR/DE/EHEB	E (NOTE 5)		11/30/83	
B-44	Forecasts of Generating Costs of Coal and Nuclear Plants	-	NRR/DE/SAB	E (NOTE 3)		11/30/83	NA
B-45	Need for Power - Energy Conservation	-	NRR/DE/SAB	E (B-2)		11/30/83	NA
B-46	Cost of Alternatives in Environmental Design	-	NRR/DE/SAB	E (DROP)		11/30/83	NA

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	NRR/DE/MEB	MEDIUM		11/30/83	
B-56	Diesel Reliability	Milstead	NRR/DSI/PSB	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	NRR/DST/RRAB	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	NRR/DE/CHEB	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		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/DSI/RSB	NOTE 4		11/30/83	
C-5	Decay Heat Update	Riggs	NRR/DSI/CPB	NOTE 4		11/30/83	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
C-6	LOCA Heat Sources	Riggs	NRR/DSI/CPB	NOTE 4		11/30/83	
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	NRR/DSI/ASB	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	NOTE 4		11/30/83	
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	E (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	NRR/DSI/RSB	NOTE 4		11/30/83	
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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	
3.	Set Point Drift in Instrumentation	Emrit	NRR/DSI/ICSB	NOTE 2		11/30/83	
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	LOW		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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 Plant Systems	Thatcher	NRR/DSI/ICSB	NOTE 3(b)	1	6/30/84	NA
21.	Vibration Qualification of Equipment	Thatcher	NRR/DE/EQB	NOTE 4		11/30/83	
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	NRR/DSI/ASB	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	NRR/DE/MTEB	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 1	1	06/30/84	
37.	Steam Generator Overfill and Combined Primary and Secondary Blowdown	Colmar	NRR/DST/GIB, NRR/DSI/RSB	A-47, I.C.1	1	06/30/85	NA
38.	Potential Recirculation System Failure as a Consequence of Injection of Containment Paint Flakes or Other Fine Debris	Milstead	NRR	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.	Contamination of Instrument Air Lines	Milstead	NRR/DSI/ASB	DROP		11/30/83	NA
44.	Failure of Saltwater Cooling System	Milstead	NRR/DSI/ASB	43		11/30/83	NA

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	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	NOTE 2		11/30/83	
49.	Interlocks and LCOs for Redundant Class 1E Tie Breakers	Sege	NRR/DSI/PSB	MEDIUM	1	12/31/84	
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	NRR/DSI/ASB	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	V'Molen	NRR	NOTE 4		11/30/83	
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	MEDIUM	1	12/31/85	
62.	Reactor Systems Bolting Applications	V'Molen	NRR	NOTE 4		11/30/83	
63.	Use of Equipment Not Classified as Essential to Safety in BWR Transient Analysis	V'Molen	NRR	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	HIGH		11/30/83	
66.	Steam Generator Requirements	Riggs	NRR/DL/ORAB	NOTE 2	1	06/30/85	
67.	<u>Steam Generator Staff Actions</u>	-	-	-		-	
67.2.1	Integrity of Steam Generator Tube Sleeves	Riggs	NRR/DE/MEB	RI (NOTE 5)	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	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
67.3.4	Reactor Vessel Inventory Measurement	Riggs	NRR/DSI/CPB	II.F.2	1	6/30/85	F-26
67.4.1	RCP Trip	Riggs	NRR/DSI/RSB	II.K.3(5)	1	6/30/85	G-1
67.4.2	Control Room Design Review	Riggs	NRR/DHFS/HFEB	I.D.1	1	6/30/85	F-08
67.4.3	Emergency Operating Procedures	Riggs	NRC/DHFS/PSRB	I.C.1	1	6/30/85	F-05
67.5.1	Reassessment of SGTR Design Basis	Riggs	NRC/DSI/AEB	LI (NOTE 5)	1	6/30/85	NA
67.5.2	Reevaluation of SGTR Design Basis	Riggs	NRR/DSI/RSB	LI (NOTE 5)	1	6/30/85	NA
67.5.3	Secondary System Isolation	Riggs	NRR/DSI/RSB	DROP	1	6/30/85	NA
67.6.0	Organizational Responses	Riggs	OIE/DEPER/IRDB	III.A.3	1	6/30/85	NA
67.7.0	Improved Eddy Current Tests	Riggs	NRR/DE/MTEB	MEDIUM	1	6/30/85	
67.8.0	Denting Criteria	Riggs	NRR/DE/MTEB	RI (NOTE 5)	1	6/30/85	NA
67.9.0	Reactor Coolant System Pressure Control	Riggs	NRR/DSI/GIB, NRR/DSI/RSB	A-45, I.C.1	1	6/30/85	NA
67.10.0	Supplement Tube Inspections	Riggs	NRR/DL/ORAB	LI (NOTE 5)	1	6/30/85	NA
68.	Postulated Loss of Auxiliary Feedwater System Resulting from Turbine-Driven Auxiliary Feedwater Pump Steam Supply Line Rupture	Pittman	NRR/DSI/ASB	HIGH	1	6/30/84	
69.	Make-up Nozzle Cracking in B&W Plants	Colmar	NRR/DE/MEB, MTEB	NOTE 3(b)	1	12/31/84	(later)
70.	PORV and Block Valve Reliability	Riggs	NRR/DSI/RSB	MEDIUM	1	6/30/84	
71.	Failure of Resin Demineralizer Systems and Their Effects on Nuclear Power Plant Safety	Emrit	NRR	NOTE 4		11/30/83	
72.	Control Rod Drive Guide Tube Support Pin Failures	V'Molen	NRR	NOTE 4		11/30/83	
73.	Detached Thermal Sleeves	Colmar	NRR	NOTE 4		11/30/83	
74.	Reactor Coolant Activity Limits for Operating Reactors	Milstead	NRR	NOTE 4		11/30/83	
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	Thatcher	NRR/DSI	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	Colmar	NRR	NOTE 4		11/30/83	
77.	Flooding of Safety Equipment Compartments by Back-flow Through Floor Drains	Colmar	NRR/DSI/ASB	HIGH		11/30/83	
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	Riggs	NRR	NOTE 4		11/30/83	
79.	Unanalyzed Reactor Vessel Thermal Stress During Natural Convection Cooldown	Colmar	NRR/DE/MEB, NRR/DSI/RSB	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 Personnel and Safety	Colmar	NRR/DHFS/PSRB	DROP	1	12/31/84	NA
82.	Beyond Design Basis Accidents in Spent Fuel Pools	V'Molen	NRR/DSI/AEB	MEDIUM		11/30/83	
83.	Control Room Habitability	Matthews	NRR	NOTE 4		11/30/83	
84.	CE PORVs	Riggs	NRR/DSI/RSB	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

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	Emrit	NRR/DE/MTEB	NOTE 2		12/31/84	B-84
87.	Failure of HPCI Steam Line Without Isolation	Pittman	NRR/DSI/RSB	HIGH		12/31/85	
88.	Earthquakes and Emergency Planning	Emrit	NRR	NOTE 4		(later)	
89.	Stiff Pipe Clamps	Riggs	NRR	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	NRR/DL	NOTE 1		12/31/85	
92.	Fuel Crumbling During LOCA	V'Molen	NRR/DSI/RSB, CPB	LOW		12/31/84	NA
93.	Steam Binding of Auxiliary Feedwater Pumps	Pittman	NRR/DSI/ASB	HIGH		12/31/84	
94.	Additional Low Temperature Overpressure Protection Issues for Light Water Reactors	Pittman	NRR/DSI/RSB	HIGH		13/31/85	
95.	Loss of Effective Volume for Containment Recirculation Spray	Milstead	NRR	NOTE 4		(later)	
96.	RHR Suction Valve Testing	V'Molen	NRR	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	NRR/DSI/RSB	HIGH		12/31/85	
100.	OTSG Le[illegible]	Riggs	NRR	NOTE 4		(later)	
101.	Break Plus Single Failure in BWR Water Level Instrumentation	V'Molen	NRR/DSI/RSB	HIGH		06/30/85	
102.	Human Error in Events Involving Wrong Unit or Wrong Train	Emrit	NRR/DHFS/LQB	HF02		06/30/85	NA
103.	Design for Probable Maximum Precipitation	Emrit	NRR/DE/EHEB	NOTE 1		12/31/85	
104.	Reduction of Boron Dilution Requirements	V'Molen	NRR	NOTE 4		(later)	
105.	Interfacing Systems LOCA at BWRs	Milstead	NRR/DSI/RSB	HIGH		06/30/85	
106.	Piping and Use of Highly Combustible Gases in Vital Areas	Colmar	NRR	NOTE 4		(later)	
107.	Generic Implications of Main Transformer Failures	Colmar	NRR	NOTE 4		(later)	
108.	BWR Suppression Pool Temperature Limits	Colmar	NRR/DSI/CSB	RI (LOW)		06/30/85	NA
109.	Reactor Vessel Closure Failure	V'Molen	NRR	NOTE 4		(later)	
110.	Equipment Protective Devices on Engineered Safety Features	Milstead	NRR	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	NRR	NOTE 4		(later)	
114.	Seismic-Induced Relay Chatter	Pittman	NRR	NOTE 4		(later)	
115.	Reliability of Westinghouse Solid State Protection System	Milstead	NRR	NOTE 4		(later)	
116.	Accident Management	Pittman	NRR/DHFS	NOTE 4		(later)	

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Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
117.	Allowable Outage Times for Diverse Simultaneous Equipment Outages		NRR	NOTE 4		(later)	
118.	Tendon Anchorage Failure	Milstead	NRR	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	NRR	NOTE 4		(later)	
121.	Hydrogen Control for Large, Dry PWR Containments	Emrit	NRR	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	Common Mode Failure of AFW Pump Discharge Isolation Valves in Closed Position	V'Molen	NRR	NOTE 4		(later)	
122.1.B	Excessive Delay in Recovery of Auxiliary Feedwater	V'Molen	NRR	NOTE 4		(later)	
122.1.C.	Interruption of Auxiliary Feedwater Flow	V'Molen	NRR	NOTE 4		(later)	
122.2	Initiating Feed-and-Bleed	V'Molen	NRR	NOTE 4		(later)	
122.3	Physical Security System Constraints	V'Molen	NRR	NOTE 4		(later)	
123.	Deficiencies in the Regulations Governing DBA and Single-Failure Criteria Suggested by the Davis-Besse Event of June 9, 1985	Rowsome	NRR	NOTE 4		(later)	
124.	Auxiliary Feedwater System Reliability	(later)	NRR	NOTE 4		(later)	
125.	Davis-Besse Loss of All Feedwater Event of June 9, 1985 - Long-Term Actions	V'Molen	NRR	NOTE 4		(later)	
	HUMAN FACTORS ISSUES						
HF01	HUMAN FACTORS PROGRAM PLAN (HFPP)						
HF01.1.0	Staffing and Qualifications	-	-	-			
HF01.1.1	Policy Statement on Engineering Expertise on Shift and Evaluate Effectiveness of Policy Statement	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.1.2	Revise and Evaluate Changes to Regulatory Guide 1.8	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.1.3	Develop a Means to Evaluate Acceptability of NPP Personnel Qualifications Program	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.1.4	Review and Evaluate Industry Programs	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
HF01.2.0	Training	-	-	-			
HF01.2.1	Evaluate Industry Training	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.2.2	Evaluate INPO Accreditation Program	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.2.3	Revise Standard Review Plan Section 13.2.3	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.3.0	Licensing Examination	-	-	-			
HF01.3.1	Develop Job Knowledge Catalogue	Pittman	NRR/DHFS/OLB	HIGH		12/31/84	
HF01.3.2	Develop Licensing Examinations Handbook	Pittman	NRR/DHFS/OLB	HIGH		12/31/84	
HF01.3.3	Develop Criteria for NPP Simulators	Pittman	NRR/DHFS/OLB	HIGH		12/31/84	
HF01.3.4	Training Requirements Package (Revise 10 CFR 55 and RGs 1.149 and 1.8)	Pittman	NRR/DHFS/OLB	HIGH		12/31/84	
HF01.3.5	Develop Computerized Exam System	Pittman	NRR/DHFS/OLB	HIGH		12/31/84	
HF01.4.0	Procedures	-	-	-			
HF01.4.1	Inspection Module for Upgrading Procedures	Pittman	NRR/DHFS/PSRB	HIGH		12/31/84	
HF01.4.2	EOP Effectiveness Evaluation	Pittman	NRR/DHFS/PSRB	HIGH		12/31/84	
HF01.4.3	Criteria for Safety-Related Operator Actions	Pittman	NRR/DHFS/PSRB	HIGH		12/31/84	
HF01.4.4	Guidelines for Upgrading Other Procedures	Pittman	NRR/DHFS/PSRB	HIGH		12/31/84	
HF01.4.5	Applications of Artificial Intelligence	Pittman	NRR/DHFS/PSRB	HIGH		12/31/84	
HF01.5.0	Man-Machine Interface (MMI)	-	-	-			
HF01.5.1	Local Control Stations	Pittman	NRR/DHFS/HFEB	HIGH		12/31/84	
HF01.5.2	Annunciators	Pittman	NRR/DHFS/HFEB	HIGH		12/31/84	
HF01.5.3	Evaluate Operational Aid Systems	Pittman	NRR/DHFS/HFEB	HIGH		12/31/84	
HF01.5.4	Computers and Computer Displays	Pittman	NRR/DHFS/HFEB	HIGH		12/31/84	
HF01.6.0	Management and Organization	-	-	-			
HF01.6.1	Development of Regulatory Position on Management and Organization	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.6.2	Evaluate Criteria for SALP Reviews	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF01.6.3	Revise Standard Review Plan Section 13.1	Pittman	NRR/DHFS/LQB	HIGH		12/31/84	
HF02	MAINTENANCE AND SURVEILLANCE PROGRAM PLAN (MSPP)						
	Phase I						
HF02.I.1	Survey Current Maintenance Practices	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.2	Maintenance Performance Indicators	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.3	Monitor Industry Activities	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.4	Participate in Standards Groups	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.5	Maintenance and Surveillance Program Integration	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.6	Analysis of Japanese/U.S. NPP Maintenance Programs	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.7	Maintenance Personnel Qualifications	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.8	Human Factors In In-Service Inspections	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	
HF02.I.9	Human Error in Events Involving Wrong Unit Wrong Train	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	

TABLE II (Continued)

Action Plan Item/ Issue No.	Title	Lead SPEB Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
HF02.II.0	Phase II Phase II Tasks To Be Determined After Resolution of Phase I	Pittman	NRR/DHFS/PSRB	HIGH		06/30/85	

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TABLE III

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

HIGH	- High Safety Priority
MEDIUM	- Medium Safety Priority
LOW	- Low Safety Priority
DROP	- Issue Dropped as a Generic Issue
USI	- Unresolved Safety Issue
I	- TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737

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 (352)													
(a) Safety													
(i) Generic Safety	94	55	1	1	106	0	9	4	12	7	2	-	291
(b) Non-Safety													
(i) Licensing	-	0	0	4	51	-	-	-	-	0	0	6	61
2. TASK ACTION PLAN ITEMS (142)													
(a) Safety													
(i) USI	-	-	0	1	14	12	-	-	-	-	-	-	27
(ii) Generic Safety	-	18	0	1	28	-	4	4	3	9	10	-	77
(iii) Regulatory Impact	-	0	0	0	2	-	-	-	1	0	0	1	4
(b) Non-Safety													
(i) Licensing	-	0	0	0	1	-	-	-	-	7	0	11	19
(ii) Environmental	-	1	0	0	6	-	-	-	-	6	0	2	15
3. NEW GENERIC ISSUES (148)													
(a) Safety													
(i) Generic Safety	-	32	5	4	15	0	12	7	5	15	39	-	134
(ii) Regulatory Impact	-	0	0	0	1	-	-	-	1	0	0	8	10
(b) Non-Safety													
(i) Licensing	-	0	0	0	0	-	-	-	-	0	0	4	4
4. HUMAN FACTORS ISSUES (34)													
(a) Safety													
(i) Generic Safety	-	0	0	0	0	0	34	0	0	0	0	-	34
TOTAL:	94	106	6	11	224	12	59	15	22	44	51	32	676

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 new or 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
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	-
E204	Effects of Fire Protection System Actuation on Safety-Related Equipment	57	-
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

TABLE IV (Continued)

AEOD Report No.	AEOD Report Title	Related Safety Issue No.	Related AEOD Report
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
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.3.1	I	II.K.3(56)
I.A.4.1(2)	NOTE 3(a)	II.K.3(54)
I.C.1		8, 18, 31, 42, 67.3.1, 67.4.3, 67.9.0
I.C.1(2)	I	37
I.C.1(3)	I	II.K.2(12), II.K.2(18), II.K.3(6), II.K.3(35), II.K.3(36), II.K.3(37), II.K.3(38), II.K.3(39), II.K.3(41), II.K.3(42), II.K.3(47), II.K.3(55), 37
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.D.1	I	56, 67.4.2
I.D.2	I	II.K.3(23), II.K.3(55)
I.D.3	MEDIUM	II.K.3(55)
I.F.1	HIGH	5

TABLE V (cont)

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues
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	MEDIUM	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		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	HIGH	B-34, 97
V.A.1		II.A.2

TABLE V (cont)

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues
TASK ACTION PLAN ITEMS		
A-2	USI [NOTE 3(a)]	B-52
A-12	USI [NOTE 2]	60
A-17	USI	II.C.3[II.K.3(4)], C-13
A-18	DROP	B-16
A-37	DROP	A-32, 11
A-38	LOW	A-32
A-40	USI	B-51
A-43	USI	B-18, C-3
A-44	USI	B-57
A-45	USI	II.E.3.2[B-4], II.E.3.3[II.K.3(8)], II.E.3.5, 67.9.0
A-46	USI	B-24
A-47	USI	19, 33, 37, 56, 67.3.1
A-48	USI	B-14
A-49	USI	28, 67.3.2
B 2	E (NOTE 3)	B-45
B-17	MEDIUM	27
B-68	DROP	A-32
C-8	HIGH	16
C-12	NOTE 3(b)	B-73
NEW GENERIC ISSUES		
17	DROP	26

TABLE V (cont)

Major Item/Issue No.	Priority	Item(s)/Issue(s) Covered in Major Issues
25	NOTE 3(a)	39
43	DROP	44
51	MEDIUM	32, 52
75	NOTE 1	I.B.1.1(6), I.B.1.1(7)
76	NOTE 4	46
HUMAN FACTORS ISSUES		
HF01.1.2	HIGH	I.A.2.6(1), I.B.1.1(6), I.B.1.1(7)
HF01.3.3	HIGH	I.A.4.2(4)
HF01.3.4	HIGH	I.B.1.1(6), I.B.1.1(7)
HF01.4.2	HIGH	I.C.9[II.K.3(49),II.K.3(50),II.K.3(51)]
HF01.4.3	HIGH	B-17
HF01.4.4	HIGH	I.C.9[II.K.3(49),II.K.3(50),II.K.3(51)]
HF01.5.3	HIGH	I.D.4
HF01.5.4	HIGH	I.D.5(5)
HF01.6.1	HIGH	I.B.1.1(1)[II.J.3.1,II.J.3.2,II.K.3(52)], I.B.1.1(2)[II.J.3.1,II.J.3.2,II.K.3(52)], I.B.1.1(3)[II.J.3.1,II.J.3.2,II.K.3(52)], I.B.1.1(4)[II.J.3.1,II.J.3.2,II.K.3(52)]
HF01.6.3	HIGH	I.B.1.1(1)[II.J.3.1,II.J.3.2,II.K.3(52)], I.B.1.1(2)[II.J.3.1,II.J.3.2,II.K.3(52)], I.B.1.1(3)[II.J.3.1,II.J.3.2,II.K.3(52)], I.B.1.1(4)[II.J.3.1,II.J.3.2,II.K.3(52)]
HF02	HIGH	I.C.9[II.K.3(49),II.K.3(50),II.K.3(51)], 102

TASK I.A.2: TRAINING AND QUALIFICATIONS OF OPERATING PERSONNEL

The objectives of this task are as follows: (1) to improve the capability of operators and supervisors to understand and control complex reactor transients and accidents, (2) to improve the general capability of an operations organization to respond rapidly and effectively to upset conditions, and (3) to increase the education, experience, and training requirements for operators, senior operators, supervisors, and other personnel in the operations organization to substantially improve their capability to perform their duties.

ITEM I.A.2.1: IMMEDIATE UPGRADING OF OPERATOR AND SENIOR OPERATOR TRAINING AND QUALIFICATIONS

This item required all operating plant licensees and all licensee applicants to provide specific improvements in training and qualifications of senior operators and control room operators. The three parts of this item are listed below.

ITEM I.A.2.1(1): QUALIFICATIONS - EXPERIENCE

DESCRIPTION

This NUREG-0660[48] item set specific experience requirements that were to be met by applicants for senior operator licenses by May 1, 1980. Applicants for senior operator licenses were required to have been a licensed operator for one year effective December 1, 1980.

CONCLUSION

This item was clarified in NUREG-0737,[98] new requirements were established and MPA F-03 was established by DL for implementation purposes.

ITEM I.A.2.1(2): TRAINING

DESCRIPTION

This NUREG-0660[48] item set the following specific requirements:

(1) Effective August 1, 1980, senior operator applicants were required to have 3 months of continuous on-the-job training as an extra person on shift.
(2) Effective August 1, 1980, control room operator applicants were required to have 3 months training on shift as an extra person in the control room.
(3) Training programs were to be modified to provide: (a) training in heat transfer, fluid flow, and thermodynamics; (2) training in the

use of installed plant systems to control or mitigate an accident in which the core is severely damaged; and (3) increased emphasis on reactor and plant transients.

CONCLUSION

This item was clarified in NUREG-0737,[98] new requirements were established, and MPA F-03 was established by DL for implementation purposes.

ITEM I.A.2.1(3): FACILITY CERTIFICATION OF COMPETENCE AND FITNESS OF APPLICANTS FOR OPERATOR AND SENIOR OPERATOR LICENSES

DESCRIPTION

This NUREG-0660[48] item required all applicants for operator and senior operator licenses, pursuant to Sections 55.10(a)(6), 55.33(a)(4), and 55.33(a)(5) of 10 CFR 55, to be certified by the highest level of the corporate management of their respective plants. This requirement was effective May 1, 1980.

CONCLUSION

This item was clarified in NUREG-0737,[98] new requirements were established, and MPA F-03 was established by DL for implementation purposes.

ITEM I.A.2.2: TRAINING AND QUALIFICATIONS OF OPERATIONS PERSONNEL

DESCRIPTION

Under the TMI Action Plan,[48] the NRC may require reactor licensees to review their training and qualification programs for all operations personnel. This is interpreted to include licensed and auxiliary operators, technicians, maintenance personnel and supervisors. The review is to examine current practices in light of the safety significance of the duties of the operations staff. If the review determines that the current practices adequately assure proper safety-related staff conduct, then documentation of the justification for this determination is required. The documentation need not be submitted to the NRC but must be maintained on site. If the review uncovers inadequacies, the licensee is required to upgrade the training and qualification practices to ensure adequate performance of operations personnel. The evaluation of this issue includes the consideration of Item I.A.2.6(3).

PRIORITY DETERMINATION

The first step in estimating the effect of training reviews on operator-error contributions to plant risk was to assemble a panel of experts from the PNL staff. This panel represented considerable experience in reactor operations, utility training programs, and reactor plant systems. The panel included members with utility field experience and reactor operator licensing examiners.

The judgments of the panel, as detailed below, are based on the two following considerations:[64]

(1) The potential effect of this issue is limited by its semi-voluntary nature, i.e., the judgment of adequacy is in the hands of the individual utilities. Furthermore, the current INPO and NRC research work in task analysis deals with generic routine operations. Plant-specific operation and operation under upset conditions are left to the individual utilities. This dilutes the effectiveness of the task analysis efforts in providing the basis for the training and qualification review.

Related issues which are supported by and in turn support this issue are the conducting of plant drills and accreditation of training programs. While neither of these is directly required by the training and qualifications review, both could be a part of the response and both would have a positive effect on personnel performance.

(2) There is a wide variation among utilities in both the training programs and the performance of operations staff. In many facilities there is much room for improvement. Therefore, while the potential effect of the training and qualifications review effort is limited, a significant overall reduction in safety-related human error for operations personnel is expected because of the wide margin available for improvement.

Assumptions

In estimating the benefit and costs, the PNL panel divided licensees into three groups:

(1) Minimally-affected group: These utilities currently have a good effective training and qualification program and good operations personnel performance. They should be minimally affected by this safety issue. The fractional population of this group is estimated to be 15% of the reactor licensees.

(2) Intermediately-affected group: These utilities' training and qualification programs and/or operations performance have room for improvement. This group, estimated to be 60% of the population, would undergo improvements and therefore be affected by the issue.

(3) Maximally-affected group: These utilities have deficiencies in their training and qualification programs and in operations personnel performance. They would be significantly affected by this safety issue and major restructuring of programs would be expected. This group is estimated to contain 25% of reactor licensees.

From the estimates for these groups, weighted composite estimates can be derived. NUREG/CR-2800[64] shows the safety benefit estimates from the panel for each of the groups and also gives the weighted averages.

The values given in NUREG/CR-2800[64] are in terms of percent changes. For inclusion into the value/impact score formula, they must be converted to other measures. The reduction in human error must be transformed into the resulting reduction in risk as measured by change in probabilistic exposure (man-rem/RY). The change in annual ORE must be transformed from percent improvement into man-rem/RY.

The reduction in risk will be developed by examining the quantitative impact on accident event frequencies of human error rates in key scenarios. The reduction in human error will thereby be translated into a reduction in accident frequency. No additional reduction due to accident mitigation will be assumed. The values given in NUREG/CR-2800[64] will be used for the best estimate of improvement: 17% for operator error and 28% for maintenance.

Frequency/Consequence Estimate

This issue centers around operator and maintenance training programs to improve personnel performance. This issue relates generically to both BWRs and PWRs, and ideally the risk reduction attributable to its resolution would be estimated by selecting a representative plant of each type. However, maintenance and operator performance impact essentially accident sequences in the risk equations. To save time, the calculations were performed for one representative PWR and inferences drawn for all reactors. The Oconee 3 (a RSSMAP PWR) plant risk equations developed in NUREG/CR-1659,[54] Vol. 4 (Hatch 1981) were used for this analysis.

It will be assumed that the 17% reduction in operator error can be applied directly to elements containing an operator error frequency and the 28% reduction can be applied directly to maintenance variables. This assumption introduces some error in the maintenance contribution. This is because some maintenance operations on nuclear systems have fixed times associated with cooldown and preparation, etc., in addition to the actual hands-on time for maintenance that would be subject to improvement through training. Maintenance done properly the first time also reduces the frequency of maintenance outage and downtime for proper repairs at some future date. Thus, fixed time periods in maintenance outages are indirectly reduced over the long run with improved maintenance performance simply because the need for maintenance may be reduced except for systems that undergo preventive maintenance at set intervals.

To calculate the total public risk reduction it was assumed that issue resolution would apply to all plants existing and planned as given in NUREG/CR-2800, Appendix C.[64] This would represent a grand total of 4,000 RY of operation (143 plants with an average life expectancy of 28 years). Implementation of the solution would provide a reduction of 9 man-rem/RY. For all plants, assuming a typical midwest-type meteorology and an average population density of U.S. reactor sites of 340 people per square mile, the total public risk reduction totals 122,400 man-rem.

Cost Estimate

Industry Cost: In estimating the costs to industry of implementing and operating under the resolution of this issue the PNL panel divided the industry once again into three categories. These groups and their estimates are shown in NUREG/CR-2800.[64] The total costs to industry for implementation is the product of the number of plants and the per-plant cost, (143)($0.335M) = $48M. The total operation cost is the product of the number of plants, the average remaining life, and the plant annual cost, (143)(28)($0.16M) = $640M. The overall cost to industry is the sum of the total implementation and operational cost, $[640 + 48]M = $688M.

NRC Cost: The cost for the NRC to implement the safety issue resolution was taken from NUREG-0660.[48] This called for 1.1 man-years of NRC effort which is equivalent to $110,000. The annual NRC effort through OIE to review the justification documentation and new training programs is estimated to be one person-year. This is $100,000/year. Over the lifetime of the completed and planned reactors this is $2.8M. Therefore, the overall cost to the NRC is the sum of the implementation and operation costs, $[0.11 + 2.8]M or $2.9M.

According to PNL estimates and calculations, the total cost for the implementation and operation of this safety issue is then $[688 + 2.9]M or approximately $691M.

Value/Impact Assessment

Based on an estimated public risk reduction of 122,400 man-rem, the value/impact is given by:

$$S = \frac{122,400 \text{ man-rem}}{\$691M}$$

$$= 177 \text{ man-rem/\$M}$$

Other Considerations

Including the occupational dose reduction (2.4×10^5 man-rem) in the value/impact equation gives a score of 524 man-rem/$M. PNL calculated[64] the occupational risk reduction for accident-related ORE to be 880 man-rem. However, it was estimated that with improved training the operational doses could be reduced by 2.4×10^5 man-rem for 143 plants over the average remaining plant lifetime.

CONCLUSION

Because of the extensive number of sequences considered to be affected by this issue, the base-case risk is high at a calculated range of from 60 to 73 man-rem/RY. Based on the potential reduction in public risk and ORE, this issue was determined to be high priority. However, in June 1985, the Commission recognized that the industry had made progress in developing programs to improve nuclear utility training and personnel qualification. As a result, the Commission adopted a Policy Statement on Training and Qualifications which made the training accreditation program managed by INPO the focus of training improvement in the industry.[777] Thus, this item was RESOLVED and no new requirements were established.

ITEM I.A.2.3: ADMINISTRATION OF TRAINING PROGRAMS

DESCRIPTION

This NUREG-0660[48] item required NRR to: (1) develop criteria and procedures to be used in auditing training programs, including those provided by reactor vendors, and (2) increase the amount of auditing.

CONCLUSION

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

ITEM I.A.2.4: NRR PARTICIPATION IN INSPECTOR TRAINING

DESCRIPTION

Historical Background

Based on NUREG-0660,[48] NRR was required to provide supplemental instruction to the OIE inspectors by the licensing and human factors staff as an addition to the already established OIE inspector training program. The purpose of such instruction would be to focus the inspector's attention on problems associated with human factors. With such training it is expected that the inspectors would become more sensitive to such problems and hence more apt to instigate corrective action and thereby improve plant safety in this area. This would provide a means of responding to the TMI-related concern on human factors problems for plant operations staff.

Safety Significance

The principal safety benefit to be derived from NRR participation in OIE inspector training is in the improvements those inspectors will bring about because of that enhanced training. The training will increase inspector awareness in human factors and personnel-related problems. In areas such as emergency procedures reviews, routine operational practices and hardware-to-human interface deficiencies may be found by inspectors and corrected. A panel of PNL experts explored the potential significance of this issue.[64] This panel included three reactor operator license examiners, members with utility field experience, experience in training as well as general reactor safety experience.

The panel envisioned that the solution of this issue would be the addition of one week of instruction in human factors to the OIE inspector training course. The staff from NRR would participate in the instruction but would probably rely on a qualified consultant to conduct the majority of the instruction. It was assumed that the principal target of the training would be the resident inspectors. The potential effect of the training upon the OIE review of emergency procedures, plant hardware and routine practices could be significant, but the overall effect is thought to be limited because of two factors: the short exposure of the inspector to human factors training, and the indirect nature of the safety benefit. That is, a marginal improvement in inspector awareness will result in some corrective actions which would result in some safety improvement. The separation between initial action and the safety benefit complicates assessment of the effectiveness of the proposed resolution of the issue.

PNL estimated[64] a human-error rate reduction of 2% for operators and maintenance personnel (operations staff assumed most likely to affect plant safety). It is important to note that this is an overall industry-wide estimate. Some isolated actions could be highly significant. The PNL estimated cost for this additional training is about $1,000.

CONCLUSION

Capabilities of inspectors could clearly be improved through the proposed training. There would be an indirect effect on risk, since better trained inspectors would identify more cost-effective improvements in plant operations. However, there is no reasonable way that the magnitude of the safety significance and cost of these improvements can be estimated quantitatively. This additional training would enhance the capabilities and thus contribute to the effectiveness and efficiency of the NRC in performing its regulatory safety mission. Thus, this training proposal should be evaluated as a Licensing Issue.

ITEM I.A.2.5: PLANT DRILLS

DESCRIPTION

The intent of this TMI Action Plan item is to upgrade operator training by requiring operating personnel to conduct plant drills during shifts. Normal and off-normal operating maneuvers would be simulated for walk-through drills on a plant-wide basis. Drills would also be required to test the adequacy of reactor and plant operating procedures.

This is an effort to reduce the risk of off-normal operating conditions by improving the capability of operators and supervisors to understand and control complex reactor transients and accidents, and also to improve the general capability of an operations organization to respond rapidly and effectively to upset conditions.

PRIORITY DETERMINATION

Assumptions

Assume that the frequency of a core-melt incident is 5×10^{-5}/RY based on WASH-1400.[16] Also, assume that operator error accounts for 50% of these events, but that the plant drills will improve operator performance by 2%. In addition, assume that the release associated with core-melt is the value averaged over the probabilities of the WASH-1400[16] accident categories for PWRs and BWRs and weighted by the number of PWRs (95) and BWRs (48). This results in a total of 2.4×10^6 man-rem/accident. The remaining average plant lifetime is assumed to be 28 years.

Frequency/Consequence Estimate

Based on the assumptions above, the reduction in the core-melt frequency resulting from the plant drills is calculated to be $(0.02)(0.50)(5 \times 10^{-5})$/RY or 5×10^{-7}/RY.

$$\text{Risk Reduction} = (5 \times 10^{-7}/\text{RY})(2.4 \times 10^{6} \text{ man-rem})(28 \text{ years})(143 \text{ reactors})$$
$$= 4{,}805 \text{ man-rem}$$

Cost Estimate

Industry Cost: The industry resources required for implementation are estimated to be one person-month per plant. This is the estimated personnel requirement associated with the utility staff time for attendance at the drill, preparation by staff and management, and staff time dedicated to the dissemination of insights gained from the drills. At a cost of $100,000/man-year and with 4.33 weeks/month, this yields a cost of $8,333/plant. Across the industry, i.e., 143 plants, this would be $1.2M.

The industry resources required annually to participate in the plant drills are estimated to be 2 man-months/plant, which includes drill attendance, preparation before the drill, and dissemination of information afterward. This would be equivalent to $16,660/RY. For the total industry (143 plants), this works out to an estimated 143 man-months/year or $2.38M/year. Given the average remaining lifetime for the plants (28 years), this gives a total operational cost of $67M.

The total cost to industry is then the sum of the implementation and operational costs, $(1.19 + 67)M or approximately $68.2M.

NRC Cost: The total costs to the NRC to implement the resolution of this issue includes NRC staff labor and services of a contractor. Since the activities of the NRC staff and the contractor are to some degree interchangeable, no attempt was made to provide separate estimates so that the total implementation cost is estimated to be $300,000. The annual cost to the NRC was also estimated to be $300,000. Again, this was assumed to contain some mixture of staff and contractor expenses. Over the average remaining life (28 years), the operational cost comes to $8.4M. Therefore, the total cost to the NRC is the sum of implementation and operation costs, $(8.4 + 0.3)M or $8.7M.

Hence, the total costs associated with this issue are $(68.2 + 8.7)M or $76.9M.

Value/Impact Assessment

Based on a public risk reduction of 4,805 man-rem, the value/impact score is given by:

$$S = \frac{4{,}805 \text{ man-rem}}{\$76.9\text{M}}$$

$$= 62 \text{ man-rem/\$M}$$

CONCLUSION

Based on the above value/impact score, the ranking of this issue would be low to medium. Because the risk may have been estimated to be well on the conservative side, the issue was given a low priority ranking. However, ongoing work by DHFS on the subject was completed in July 1985 and published for information only as NUREG/CR-4258.[800] Thus, this item was RESOLVED and no new requirements were established.[801]

ITEM I.A.2.6: LONG-TERM UPGRADING OF TRAINING AND QUALIFICATIONS

ITEM I.A.2.6(1): REVISE REGULATORY GUIDE 1.8

Items I.A.2.6(1), I.A.2.6(2), I.A.2.6(3), and I.A.2.6.(5) have been combined and evaluated together.

DESCRIPTION

Historical Background

Item I.A.2.6 of the TMI Action Plan[48] calls for the long-term upgrading of training and qualifications for operations personnel. The specific paragraphs of this item in NUREG-0660[48] called for a revision of Regulatory Guide 1.8,[226] (ANSI/ANS 3.1),[253] in order to incorporate short-term requirements into this issue and any other changes resulting from a national standards effort. Also, it is stated that more explicit guidance regarding exercises in simulator requalification programs will be included in the regulatory guide (Recommendation 8 of SECY-79-330E[251]) as will qualifications of shift supervisors and senior reactor operators [NUREG-0585,[174] Recommendations 1.6(1) and (2)]. In addition, based on the NRC staff review of NRR-80-117,[252] recommendations will be made to the Commission and Commission decisions will be factored into the regulatory guide or regulation changes. Moreover, appropriate revisions to 10 CFR 55, Operator Licenses, are to be recommended for action by the Commission in order to incorporate the applicable short-term changes plus requirements based on Commission action on SECY-79-330E[251] for mandatory simulator training for applicants for licenses (Recommendation 4); mandatory simulator training in requalification programs (Recommendation 7); NRC administration of requalification examinations (Recommendation 9 as modified by the Commission); and mandatory operating tests at simulators (Recommendation 11). Finally, it is noted that the Nuclear Waste Policy Act of 1982, Public Law 97-425, Section 306 authorized and directed NRC to promulgate regulations or guidance for the training and qualifications of civilian nuclear power plant personnel. A task force has been formed within NRC as a result of this bill. As part of the task force objectives, Items I.A.2.6 (1, 2, and 3) are to be addressed.

The numerical assessment of this safety issue was conducted by the PNL staff[64] with experience in reactor operator licensing, reactor operation, and general reactor safety in consultation with General Physics Corporation. General Physics Corporation provides utility training services and has significant experience in reactor simulators, providing procurement and startup assistance, operation and maintenance services, and simulator modifications.

Safety Significance

A public risk reduction is anticipated as a result of a reduction in core-melt frequency which follows from a reduction in operator error rates. Reduction in operator errors is expected to result from the upgraded training and qualifications which form the assumed resolution of this safety issue.

Possible Solutions

The upgrades are assumed to include an increase in time spent in simulator operation both in training and in requalification. The simulator time is assumed to improve in quality as well as quantity. Emphasis on improvements on the operators' diagnostic capability is felt to be especially important in contributing to a reduction in core-melt frequency. Furthermore, the enforcement activities in term of NRC-administered examinations and OIE inspection of training programs is likely to emphasize the value of this long-term training and qualification of reactor operators.

PRIORITY DETERMINATION

Assumptions

It is assumed that the resolution of this safety issue will take the form of upgrading utility training and qualification programs that will represent a major enhancement of the training and qualification programs.

It is noted that many of the TMI Action Plan Items associated with operator training are interrelated and it is, therefore, difficult to assess them independently. For example, this issue is related to I.A.4.1, Initial Simulator Improvement, which deals with the improvement of simulators and provides for more realistic modeling of the plant whereas this issue, [I.A.2.6(1,2,3,5)], deals with training improvements, including the enhanced use of existing simulators. Either issue, by itself, would improve operator performance. However, there may be significant overlaps in improving operator performance if both items were implemented. Even though it is recognized that the total improvement would be less than the sum of the individual contributions when each is assessed separately, the extent of any overlap is not identified here.

Based on engineering judgment, it was estimated by the PNL panel that the resolution of this safety issue would result in a 30% reduction in operator error rates. The number of plants to which this issue is applicable is assumed to be 95 PWRs and 49 BWRs with average lifetimes of 28.5 years and 27 years respectively.

For the analysis performed by PNL,[64] Oconee-3 is taken as the representative PWR plant. It is assumed that the fractional risk and core-melt frequency reductions for the representative BWR (Grand Gulf) will be equivalent to those for the representative PWR. Therefore, the analysis is conducted only for the PWR but the fractional risk and core-melt frequency reductions are also applied to the BWR. The dose calculations are based on a reactor site population density of 340 people per square mile and a typical mid-west meteorology is assumed.

Frequency/Consequence Estimate

Based on the affected accident sequences and the parameters affected by this safety issue resolution (SIR), the original core-melt frequencies of 8.2×10^{-5}/RY for PWRs and 3.71×10^{-5}/RY for BWRs are calculated to be reduced by about 16%. The associated reduction in public risk is 31 man-rem/RY for PWRs and 37.4 man-rem/RY for BWRs resulting in a total public risk reduction of 132,600 man-rem.

Cost Estimate

Industry Cost: The resolution of this safety issue was assumed to be a major enhancement of the training and qualification programs. The programs would have to be upgraded in order to meet the requirements of INPO accreditation. These requirements are assumed to be far-reaching and require significant effort on the part of utility training staffs. The amount of effort will vary among the utilities, depending on the present state of their programs. The effort required to implement the program is estimated by the PNL panel to require 10 to 20 man-years of effort for each plant. The mean value is expected to be shifted toward the lower end since many utilities are currently improving their training programs. A 12 man-year effort is taken as the central estimate.

Operation under the upgraded programs would require enhanced training activities and more operator time in training. The training staff is estimated to require three additional people. It is assumed the major cost of additional operator time can be estimated from increased time at simulators. It is estimated that 40 hours of simulator time will be added to operator training and requalification. For 20 operators per year passing through these programs, this is equivalent to 800 additional hours. It is further assumed that operators can be trained three at a time on the simulator and that simulator time can be acquired for $600/hour. This gives an additional simulator cost of $160,000/year. The industry costs are estimated as follows:

(1) Implementation of the SIR

(12 man-yrs/plant) (49 + 95) plants ($100,000/man-yr) = $173M

(2) Operation and Maintenance of the SIR

(a) Labor

Training Staff = (3 man-yr/RY) (52 man-weeks/man-year)
= 156 man-weeks/RY

Operators = (800 man-hr/RY/(40 man-hours/man-week)
= 20 man-wk/RY

Thus, the total labor is 176 man-wk/RY.

(b) Simulator Time (Operators)

(800 man-hours/RY)/(3 man-hours/simulator-hr) = 267 simulator-hr/RY

Therefore, the industry cost per plant-year for operation and maintenance is given by:

$$\left[\frac{176\text{ man-wk}}{\text{RY}}\right]\left[\frac{\$100{,}000/\text{man-yr}}{52\text{ man-wk/man-yr}}\right] + \left[\frac{267\text{ simulator-hr}}{\text{RY}}\right]\left[\frac{\$600}{\text{simulator-hr}}\right]$$

= 500,000/RY

Therefore, for all affected plants, the total industry cost for operation and maintenance is given by:

($500,000/RY) [(49)(27) + (95)(28.5)] RY = $2,000M

The total industry cost for implementation, operation, and maintenance of the solution is then $(173 + 2,000)M or $2,173M.

NRC Cost: The NRC effort to implement the resolution of this issue would be significant. It is estimated in NUREG-0660[48] that 5.4 man-years plus $259,000 would be required. Some of these development activities have been completed. However, much work remains to be done. The remaining effort is estimated to be 4.5 man-years and $100,000.

The operational activities of the NRC would include reviews of training programs, increase inspection and additional examination. The annual labor for reviews and inspections is estimated to be equivalent to 3 person-years. The principal addition in examinations is assumed to be NRC conduct of a portion of requalification examinations. It is assumed the NRC will conduct 25% of the requalification examinations and the 20 operators are requalified at each plant every year. It is estimated that one person-month is required for each plant. This assumes the five (25% of 20) operators selected for NRC examination at each plant are tested at the same time. NRC costs are estimated as follows:

(1) Implementation of the SIR

Staff Labor + Other Costs
= (1.4 man-wk/plant)($1,600/man-wk) + ($100,000/144 plants)
= $3,386/plant

Total cost for all affected plants is ($3,386/plant)(144 plants) or $488,000.

(2) Review of Maintenance and Operation of SIR

(a) Review and Inspection = (3 man-yr/yr)(52 man-wk/man-yr)/144 plants
= 1.08 man-wk/RY

(b) Examination = (1 man-month/RY)(3.7 man-wk/man-month)
= 3.7 man-wk/RY

Thus, the total time spent is 4.78 man-wk/RY.

The NRC cost per plant-yr due to review of operation and maintenance is (4.78 man-wk/RY)($1,900/man-wk) = $9,088/RY.

The total NRC cost for operation and maintenance of the SIR is then
($9,088)[(49)(27) + (95)(28.5)] = ($9,088)(4,030) = $36.6M

Therefore, the total industry and NRC costs are estimated to be $[2,173 + 0.488 + 36.6]M = $2,210M.

Value/Impact Assessment

Based on the estimated public risk reduction of 132,600 man-rem, the value/impact score is given by:

$$S = \frac{132{,}600 \text{ man-rem}}{\$2{,}210\text{M}}$$

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

Other Considerations

The total occupational risk reduction is associated only with accident avoidance inasmuch as there is no dose associated with implementation or maintenance of this SIR. With a dose of 20,000 man-rem associated with accident cleanup and with the calculated reductions in core-melt frequencies of 1.3×10^{-5}/RY and 5.9×10^{-5}/RY for PWRs and BWRs, respectively, the total occupational dose reduction is calculated to be 860 man-rem.

CONCLUSION

Although the value/impact score was low, this issue was determined to be high priority because of the large potential public risk reduction. However, with the publication of the HFPP in NUREG-0985, Revision 1,[651] Item I.A.2.6(1) was determined to be covered in Issue HF01.1.2.

ITEM I.A.2.6(2): STAFF REVIEW OF NRR 80-117

This item was evaluated in Item I.A.2.6(1) above and, in accordance with an RES memorandum,[437] was RESOLVED. No new requirements were established.

ITEM I.A.2.6(3): REVISE 10 CFR 55

This item was evaluated in Item I.A.2.6(1) above and, as a result of the Nuclear Waste Policy Act of 1982 (Public Law 97-425), was determined to be covered in Item I.A.2.2.[438]

ITEM I.A.2.6(4): OPERATOR WORKSHOPS

DESCRIPTION

Historical Background

On the basis of NUREG-0660,[48] NRR was required to develop a Commission paper on training workshops for licensed personnel. NUREG-0585,[174] the source of this safety issue, states that the intent of the issue is to conduct seminar-type workshops to exchange information on operations experience between the NRC and licensees and among licensees. This would assist in the improvement of operator performance and in improvements to reactor regulation, both resulting in improved safety. The proposed requirements would have one representative for each shift at each unit attend such a workshop annually.

Safety Significance

It is expected that there are two potential pathways to improved safety benefit emerging from this issue: (1) improved operator performance through the sharing of safety-related experiences and (2) the effect of improved regulation arising out of interaction between the operators and the NRC attending the workshops. The second pathway is considered to be a second-order effect and very difficult to quantify. Therefore, it was assumed that all the benefit would be derived through the reduction in operator-error rates.

PRIORITY DETERMINATION

Assumptions

PNL has conducted and is conducting a series of these workshops for NRR. In the assessment of this issue, PNL staff responsible for these workshops were consulted. Their judgments form the basis of our analysis.

This analysis assumes the major gains in reactor safety will come through the improvement in operator performance; that is, a reduction in their error rates. There is also a pathway to improve safety by means other than human performance through improved regulations developed from operator input at the workshops. The latter would be extremely difficult to quantify so that only the human error rate-reduction pathway to improved safety will be treated.

A panel of PNL experts was assembled and included staff that conduct operator licensing examinations, staff with experience in reactor operations, reactor safety and risk assessment, and the staff responsible for the conduct of the current operator feedback workshops. This panel produced the estimates that form the basis of this analysis.

The analysis is based on the following additional assumptions:

1. Applicable Plants: 95 PWRs and 48 BWRs

2. Selected Analysis Plant: Oconee 3 - representative PWR. It is assumed that the fractional risk and core-melt frequency reductions for the representative BWR (Grand Gulf) will be equivalent to those for the representative PWR. Therefore, the analysis is conducted only for the PWR, but the fractional risk and core-melt frequency reductions are also applied to the BWR.

3. Affected Accident Sequences and Base-Case Frequencies: Most sequences are affected. The affected sequences and the base-case frequencies are shown in NUREG/CR-2800.[64]

4. Affected Release Categories and Base-Case Frequencies: All release categories are affected by issue resolution. The original base-case frequencies are used as given below.

Oconee	Grand Gulf
PWR-1 = 1.10×10^{-7}/RY	BWR-1 = 1.09×10^{-7}/RY
PWR-2 = 1.0×10^{-5}/RY	BWR-2 = 3.35×10^{-5}/RY
PWR-3 = 2.86×10^{-5}/RY	BWR-3 = 1.44×10^{-6}/RY

Frequency/Consequence Estimate

The PNL panel estimated[64] the most likely reduction in human error rates for operators due to the conduct of the proposed workshops would be 3%. This is assuming the workshops are conducted in the manner now perceived. That is, to focus on data gathering for the NRC. This reduces the amount of time that could be devoted to inter-licensee sharing of operational experiences which would have a more direct effect on safety-related operational performance in the plants. The possible range of reduction stretched from 1% to 10%. If the focus could be shifted toward the inter-licensee exchange of operational experiences, the most likely reduction in error rate would shift upward. However, it is not expected to exceed 10%.

Based on the PNL estimates and calculations,[64] and assuming a typical midwest-type meteorology and an average population density of U.S. reactor sites of 340 people per square mile, the public risk reduction is 7,140 man-rem for 143 plants with an average existing life span of 28 years. The occupational dose reduction is minor at a calculated value of 46 man-rem.

Cost Estimate

Industry Cost: The industry resources required for implementation are estimated to be one person-month per plant. This is the estimated personnel requirement associated with the trial workshops currently being conducted. It includes utility staff time for attendance of the workshop, preparation by staff and management, and staff time dedicated to the dissemination of insights gained at the workshop. At a cost of $100,000/man-year and with 4.33 weeks/month, this yields a cost of $8,333/plant. Across the industry, i.e., 143 plants, this would be $1.19M.

The industry resources required annually to participate in the training workshops are estimated to be the same as those for implementation. That is, one person-month per plant, which includes workshop attendance, preparation before the workshop, and dissemination of information afterward, would be needed. This would be equivalent to $8,333/RY. For the total industry (143 plants), this works out to an estimated 143 man-months/year or $1.19M/year. Given the average remaining lifetime for the plants, this gives a total operational cost of $33.3M. Therefore, the total industry cost associated with this issue is $34.5M.

NRC Cost: The total cost to the NRC to implement the resolution of this issue was estimated to be $0.3M. This includes NRC staff labor and services of a contractor. Since the activities of the NRC staff and the contractor are to some degree interchangeable, no attempt was made to provide separate estimates. The annual cost to the NRC was also estimated to be $0.3M. Again, this was assumed to contain some mixture of staff and contractor expenses. Over the average remaining life, the operational cost comes to $8.4M. While not specific, these estimates for implementation and operation are firmly based on the experience of conducting the present trial workshops. Therefore, the total cost to the NRC is the sum of implementation and operation costs which amounts to $8.7M.

Value/Impact Assessment

Based on the estimated public risk reduction of 7,140 man-rem, the value/impact score is given by:

$$S = \frac{7{,}140 \text{ man-rem}}{\$(34.5 + 8.7)\text{M}}$$

$$= 165 \text{ man-rem/\$M}$$

Other Considerations

The accident avoidance cost is the product of the change in accident frequency (ΔF) and the estimated cost to the utility of a major accident (A). This latter term is estimated[64] to be \$1.65 Billion. The cost per plant-year is then estimated to be:

PWRs: $(\Delta F)(A) = (7 \times 10^{-7})(\$1{,}650M)/RY = \$1{,}200/RY$
BWRs: $(\Delta F)(A) = (3.2 \times 10^{-7})(\$1{,}650M)/RY = \$530/RY$

The total cost for all plants is the per-plant-year cost multiplied by the number of plants (N) and the average remaining lifetime (T) for each type of plant:

$$\Sigma(NT)(\Delta F)(A) = \$(95)(28.5)(1{,}200)M + \$(48)(27.0)(530)M = \$3.9M$$

CONCLUSION

Because of the extensive number of sequences considered by PNL to be affected by this issue, the base-case risk is high at a calculated range of from 60 to 73 man-rem/RY. With a value/impact score of 165 man-rem/\$M and an estimated risk reduction of 7,140 man-rem, this issue was given a medium priority ranking.

The staff conducted three workshops and a mail survey in order to evaluate the effectiveness of both mechanisms for obtaining feedback to the NRC from utility operating staffs. The results of these two approaches were documented in NUREG/CR-3739[802] and NUREG/CR-4139,[803] respectively. The staff concluded that both feedback mechanisms have proved to be effective methods of gathering data from operations personnel and did not recommend conducting workshops or surveys on an annual basis; it would be preferable to use such mechanisms judiciously when a real need existed.[804] Thus, this item was RESOLVED and no new requirements were established.

ITEM I.A.2.6(5): DEVELOP INSPECTION PROCEDURES FOR TRAINING PROGRAM

This item was evaluated in Item I.A.2.6(1) above and, in accordance with an OIE memorandum,[379] was RESOLVED. No new requirements were established.

ITEM I.A.2.6(6): NUCLEAR POWER FUNDAMENTALS

DESCRIPTION

This NUREG-0660[48] item called for NRR to develop requirements for the inclusion of nuclear power fundamentals within the instruction given to reactor operators. This arose out of a concern[174] that the 12 weeks of fundamentals training given to operators at that time was insufficient.

PRIORITY DETERMINATION

In order to assess this safety issue, a panel of experts was assembled from the PNL staff. This panel was comprised of members experienced in reactor operator licensing, reactor operations, utility field work, and general reactor safety areas. The results of the PNL assessment are contained in NUREG/CR-2800.[64]

Assumptions

The panel felt there had been significant progress across the industry in the area of instruction in nuclear power fundamentals since the issuance of NUREG-0585[174] in 1979. Further increase in emphasis on fundamentals was felt to be unlikely to improve operator performance. The current trend in operator licensing examinations is to stress operational knowledge and de-emphasize fundamentals. This supports the view that further fundamental training would not add to plant safety.

It was assumed that, if implemented, the additional nuclear power fundamentals training would add 4 weeks to the training period. Also, it was assumed that 20 operators complete the training course each year at every plant. In addition, one full-time instructor was assumed to be required. This yields 80-man-weeks for the operators and 44 man-weeks for the instructors, or 124 man-weeks/plant overall each year. To implement this practice, an effort equivalent to one year of operation (124 man-weeks) was estimated to be required.

Frequency/Consequence Estimate

Safety issues which deal with operator training can affect the public risk by improvements in the operator safety-related performance. This can lead to a reduction in core-melt frequency and a reduced probabilistic risk. For this safety issue the PNL panel felt that the current level of instruction in nuclear power fundamentals was adequate. Further emphasis of fundamentals was viewed as not likely to improve operator safety performance. Therefore, there would be no measurable public risk reduction associated with the implementation of this issue. The PNL panel also saw no reduction in occupational dose associated with the implementation of the solution.

Cost Estimate

NRC effort to implement the solution is estimated[48] to be 0.4 man-year or approximately 18 man-weeks. No added costs are estimated for operation for the NRC. The review of the additional instruction could be contained in the current routine function thereby causing no added expense.

Value/Impact Assessment

Based on the judgment that there would be no risk reduction resulting from this issue, the value/impact score is zero.

CONCLUSION

In view of the fact that it is believed that the current level of instruction in nuclear power fundamentals is adequate for reactor operators, further emphasis of fundamentals as required by this issue is viewed as not likely to improve operator safety performance. The resulting value/impact score of zero indicates that this issue should be DROPPED from further consideration.

ITEM I.A.2.7: ACCREDITATION OF TRAINING INSTITUTIONS

DESCRIPTION

Historical Background

Based on the requirements of NUREG-0660,[48] this item required NRR to complete a study to establish the procedures and requirements for NRC accreditation of reactor operator training programs. The resulting study would be developed into a Commission paper describing the various options for accreditation.

Safety Significance

There are two aspects to the safety benefit for this issue. One is the reduction of public risk through the improvement of operator performance, which is expected from the improved training accreditation. The second is a reduction in occupational exposure. This will primarily be for operators who often supervise maintenance or perform other duties in radiation zones. However, some reduction in routine occupational exposure can also be expected for other operations personnel as a result of the increased awareness by the operators.

Possible Solution

In order to assess this safety issue, a panel of experts was assembled from the PNL staff. This panel was comprised of members experienced in reactor operator licensing, reactor operations, utility field work, and general reactor safety areas.

The panel envisioned the resolution of this safety issue as the formation of an accreditation board consisting of representatives from the NRC, industry, and academia. This board would develop and apply criteria for accreditation. This would include training programs of utilities, university-related programs, and independent training institutions. While theoretically applying to training for all operations staff, the PNL panel felt the current thrust was focused on reactor operators. Therefore, the assessment was made assuming only operators would be affected.[64]

PRIORITY DETERMINATION

Assumptions

The views of the panel include an awareness of the fact that some training programs are very near to accreditation already. Either through association with the universities or through other means of providing high quality instruction, these programs would be likely to acquire accreditation from the board easily. Other training programs are not so well prepared for accreditation and may require significant effort and expense to upgrade them. Some savings may be gained for multi-unit sites in sharing costs.

Therefore, the resolution of this safety issue was assumed to be an improvement in operator performance. For some utilities, approximately 10% of the total, this issue will have essentially no effect. This is because: (1) their current training programs would be accredited with little effort and (2) the quality of their programs is sufficiently high that accreditation would result in no discernible improvement in their operators' performance. Other utilities will see varying degrees of improvement. Those with training programs that are below the accreditation standards will be brought up nearer to the high quality enjoyed by the outstanding utilities. Overall, the effect on operator human error is estimated to be a reduction of 10% across the affected portion of the industry. The detailed assumptions for this analysis are as follows:

1. Applicable Plants: BWRs and PWRs - 90% of total plants; 43 BWRs, 86 PWRs, or 129 plants in all.

2. Selected Analysis Plant: Oconee 3 - representative PWR. It is assumed that the fractional risk and core-melt frequency reductions for the representative BWR (Grand Gulf) will be equivalent to those for the representative PWR. Therefore, the analysis is conducted only for the PWR, but the fractional risk and core-melt frequency reductions are also applied to the BWR.

Frequency/Consequence Estimate

Based on the PNL analysis,[64] and assuming a typical midwest-type meteorology and an average population density of U.S. reactor sites of 340 people per square mile, the anticipated public risk reduction is calculated to be 26,180 man-rem.

Cost Estimate

The PNL panel estimated[64] the costs associated with implementation and operation of the resolution to this safety issue. The one-time costs to industry to implement the change initially was estimated to be in the range of $0.1M to $1M per reactor. Those with training programs closer to accreditable status would enjoy the smaller costs. The best estimate for the average plant was taken to be $0.3M. Operation under the accreditation program was estimated to cost between $0.05M and $0.25M per plant annually for additional funding to maintain an accredited training program. The best estimate was $0.1M/plant annually.

The cost to the NRC to implement the accreditation was estimated to be $0.635M which is equivalent to 330 person-weeks. The annual operational cost to the NRC is estimated[64] to be $100,000 or one man-year.

The detailed breakdown of these costs are as follows:

$300,000/Plant Industry Implementation (approximately 3 man-yrs):

- to review accreditation standards
- to compare the present utility practices with the developed standards
- plan the necessary upgrades
- implement the program upgrades to fulfill the accreditation requirements.

<u>$100,000/Plant-yr Industry Operation and Maintenance:</u>

- time invested by the staff in upgraded training (increased course time, quality, etc.)

- instruction upgrade (time, quality, etc.)

<u>$500,000 NRC Implementation (approximately 5 man-yrs)</u>

- predicated on the possibility that INPO accreditation will not be forthcoming; NRC may have to do

- NRC to develop accreditation standards, regulations, and implement to adoption by the industry.

<u>$100,000 NRC Operation and Maintenance (approximately 1 man-yr/yr)</u>

- additional OIE efforts to assure industry maintenance of standards (all plants).

The total costs for this safety issue are, therefore, estimated[64] by PNL as follows:

1.	Implementation of the SIR by Industry		$ 39,000,000
2.	Operation and Maintenance of the SIR by Industry		360,000,000
3.	NRC Implementation of the SIR		635,000
4.	NRC Operation and Maintenance of the SIR		2,800,000
		Total:	$402,435,000

<u>Value/Impact Assessment</u>

Based on the estimated public risk reduction of 26,180 man-rem, the value/impact score is given by:

$$S = \frac{26{,}180 \text{ man-rem}}{\$402.4\text{M}}$$

$$= 65 \text{ man-rem/\$M}$$

<u>Other Considerations</u>

The industry accident avoidance cost was estimated by PNL[64] to be $14M. The occupational risk reduction is estimated to be 22,170 man-rem resulting from accident avoidance (170 man-rem) and from operation and maintenance of the SIR (22,000 man-rem).

<u>CONCLUSION</u>

Although the value/impact score was low, this issue was determined to be medium priority because of the magnitude of the potential public risk reduction. However, in June 1985, the Commission recognized that the industry had made progress in developing programs to improve nuclear utility training and personnel qualification. As a result, the Commission adopted a Policy Statement on Training and

Qualifications which made the training accreditation program managed by INPO the focus of training improvement in the industry.[777] Thus, this item was RESOLVED and no new requirements were established.

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.

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

54. NUREG/CR-1659, "Reactor Safety Study Methodology Application 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, February 1983.

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

174. NUREG-0585, "TMI Lessons Learned Task Force Final Report," U.S. Nuclear Regulatory Commission, October 1979.

226. Regulatory Guide 1.8, "Personnel Selection and Training," U.S. Nuclear Regulatory Commission, May 1977.

251. SECY-79-330E, "Qualifications of Reactor Operators," July 30, 1979.

252. NRR-80-117, "Study of Requirements for Operator Licensing," February 4, 1980.

253. ANSI/ANS 3.1, "Selection, Qualification, and Training of Personnel for Nuclear Power Plants," American National Standards Institute, 1981.

379. Memorandum for H. Denton from R. DeYoung, "Draft Report on the Prioritization of Non-NRR TMI Action Plan Items," January 24, 1983.

437. Memorandum for H. Denton from R. Minogue "Draft Report on the Prioritization of Non-NRR TMI Action Plan Items," March 29, 1983.

438. Memorandum to Office Directors from W. Dircks, "NRC Actions Required by Enactment of the Nuclear Waste Policy Act of 1982," January 19, 1983.

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

777. Memorandum for W. Dircks from H. Denton, "Closeout of TMI Action Plan Items I.A.2.2 and I.A.2.7 Training and Qualifications of Operating Personnel," June 24, 1985.

800. NUREG/4258, "An Approach to Team Skills Training of Nuclear Power Plant Control Room Crews," U.S. Nuclear Regulatory Commission, July 1985.

801. Memorandum for W. Dircks from H. Denton, "Team Training for Nuclear Power Plant Control Room Crews," July 10, 1985.

802. NUREG/CR-3739, "The Operator Feedback Workshop: A Technique for Obtaining Feedback from Operations Personnel," U.S. Nuclear Regulatory Commission, September 1984.

803. NUREG/CR-4139," The Mailed Survey: A Technique for Obtaining Feedback from Operations Personnel," U.S. Nuclear Regulatory Commission, May 1985.

804. Memorandum for W. Dircks from H. Denton, "TMI Action Plan Item I.A.2.6(4)," September 25, 1985.

TASK I.A.3: LICENSING AND REQUALIFICATION OF OPERATING PERSONNEL

The objectives of this task are as follows: (1) to upgrade the requirements and procedures for nuclear power plants operator and supervisor licensing to assure that safe and competent operators and senior operators are in charge of the day-to-day operation of nuclear power plants, and (2) to increase the requirements for initial issuance of licenses and for license renewals and provide closer NRC monitoring of licensed activities.

ITEM I.A.3.1: REVISE SCOPE OF CRITERIA FOR LICENSING EXAMINATIONS

DESCRIPTION

This NUREG-0660[48] item called for NRR to notify all operator license holders and applicants of the new scope of examinations and criteria for issuance of reactor operator (RO) and senior reactor operator (SRO) licenses and renewal of licenses. Simulator examinations were to be included as part of the license examination. As a result of P.L. 97-425, it was determined that additional staff work on the issue was required and a proposed rule for operator licensing was presented to the Commission in SECY-84-76.[593] Approval of this rule would effectively close out this item.

CONCLUSION

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

ITEM I.A.3.2: OPERATOR LICENSING PROGRAM CHANGES

DESCRIPTION

This TMI Action Plan item[48] called for NRR to take the following actions:

(1) Develop and implement a plan to relocate Operator Licensing Branch (OLB) examiners at Nuclear Power Plant Simulator Training Centers or in Inspection and Enforcement Regions.
(2) Conduct a study of the staffing of the operator licensing program and the qualifications and training of examiners.
(3) Develop and implement a plan to report operator errors and to act on operator errors with respect to continuation of licensing.

As a result of the above actions, the following accomplishments were made:

(1) "The administering of examinations and issuance/renewal of operator licensing will be transferred to Region III in FY 1982 and to Region II in FY 1983. All regions will have operator licensing authority in FY 1984. NRR will provide oversight and guidance, including examination procedures and criteria."[88]

(2) A study of the staffing of the operator licensing program and the qualifications and training of examiners was completed in November 1980 and documented in NUREG/CR-1750.[89]

(3) A plan for reporting operator errors and for acting on operator errors with respect to continuation of licensing was developed in NUREG/CR-1750.[89] However, after review of this recommended plan, DHFS concluded that no further action was required.[440]

CONCLUSION

This item has been RESOLVED and no new requirements were established.

ITEM I.A.3.3: REQUIREMENTS FOR OPERATOR FITNESS

DESCRIPTION

Historical Background

This safety issue as described in NUREG-0660[48] calls for the NRC to develop a regulatory approach to: (1) provide assurance that applicants for RO and SRO licenses are psychologically fit, and (2) prohibit licensing of persons with histories of drug and alcohol abuse or criminal backgrounds. The regulations will be applied to all current and future operating power plants.

The accomplishments in the program include the publication of NUREG/CR-2075[289] and NUREG/CR-2076.[290] Additionally, a proposed rule addressing alcohol and drug use and the broader issue of fitness for duty of operating licensee personnel and contractors was concurred in by several NRC offices and forwarded to the EDO on April 16, 1982. The proposed fitness for duty rule was issued for public comment in the Federal Register on August 15, 1982, with the public comment period extending to October 5, 1982. A final rule package was completed on December 1, 1982 and a final rule was expected to be published by April 1, 1983. The rule, if promulgated, would require facilities licensed under 10 CFR Part 50.21(b) or Part 50.22 to establish and implement adequate written procedures to provide reasonable assurance that persons with unescorted access to protected areas of nuclear power plants, while in those areas, are not under the influence of alcohol, other drugs or otherwise unfit for duty due to mental or physical impairments. Secondly, a proposed rule amending 10 CFR Part 73.56 regarding access authorization for nuclear power plants has not been completed, although a value/impact analysis in support of the proposed rule has been prepared by the NRC staff.

This issue was assessed by PNL[64] in consultation with a number of engineers who have expertise in reactor operator licensing, reactor operations, utility field work, and general reactor safety areas.

Safety Significance

There could be significant damage if impaired personnel were performing critical safety operations. Legal and institutional problems may limit a thorough implementation of the proposed program. Given that an adequate program were implemented at all power plants and integrated into overall plant operations, the new program would reduce operator error which in turn would lower the risk associated with operation of the power plant.

Possible Solutions

This issue has two components: the first involves initial access to protected areas of nuclear power plants and the second involves continuing fitness for duty once initial access has been granted. The proposed fitness for duty rule, issued for public comment on August 15, 1982, is directed toward the second component of this issue, mandating behavioral observation programs for power plants licensed by the NRC. Behavioral observation is also a part of the proposed Access Authorization Rule directed toward the first component of this safety issue.

The second component of this safety issue deals with limiting access of psychologically unstable individuals to vital plant areas. This component will have a major cost impact on the industry because this access authorization program is comprehensive in that it is aimed at limiting the access to vital plant areas of disgruntled employees, psychologically unsuitable employees, as well as personnel under the influence of drugs or alcohol.

The access authorization program has the following three parts: (1) background search, (2) psychological assessment, and (3) behavior observation. The first two parts would occur prior to granting an individual an unescorted access authorization to protected and vital areas, and the last part would be an ongoing activity for individuals who have been granted an unescorted access authorization. The background check would examine an individual's past for unstable activities, a criminal record, credit problems, and previous employment problems. It has been established by NRC personnel that data on psychological screening shows that for white-collar workers, 2 to 3% are identified as unstable and that for blue-collar employees, the rate is 7 to 10%. These figures provide a background for the assumptions to be made in the priority determination.

PRIORITY DETERMINATION

Assumptions

The major result of this safety issue was assumed to be a reduction in operator error. For some utilities, this new system may result in some reduction in operator error whereas in others the system it may have no discernible effect. Based on engineering judgment, an average of about 2% was arrived at by PNL to apply to all currently operating and future plants. Thus, this issue assumes the implementation of the access authorization system at all 134 plants either under construction (63) or already in operation (71), with average lifetimes of 28.8 yrs for 90 PWRs and 27.4 yrs for 44 BWRs. Thus, the total remaining life of the affected plants is [(28.8)(90) + (27.4)(44)]RY or 3,798 RY.

Neither the implementation, operation, or maintenance of this SIR would involve any changes in occupational dose accrued by any personnel.

For the analysis performed by PNL,[64] Oconee 3 is taken as the representative PWR. It is assumed that the fractional risk and core-melt frequency reductions for the representative BWR (Grand Gulf) will be equivalent to those for the representative PWR. Therefore, the analysis is conducted only for the PWR, but the fractional risk and core-melt frequency reductions are also applied to the BWR.

Frequency/Consequence Estimate

All release categories are affected by this safety issue but the principal release categories affected by the SIR are 3, 5, and 7. The numerical calculations are based on these categories. The dose calculations are based on a reactor site population density of 340 people per square mile and a typical midwest meteorology is assumed.

The calculated reduction in core-melt frequencies are 4×10^{-7}/RY for PWRs and 1.8×10^{-7}/RY for BWRs. Based on this, the total estimated public risk reduction is 16,000 man-rem. The occupational risk reduction for implementation, operation, and maintenance is zero.

Cost Estimate

Industry Cost: A value/impact analysis in support of the anticipated rule of access authorization has been prepared by the NRC staff and cost estimates for industry have been developed. These cost estimates, which have been reviewed and accepted by AIF, are as follows:

(1) For all existing plants, the implementation cost is $140,000/plant and includes the preparation of the plant and associated procedures ($33,000), licensee management and clerical staff ($63,000), training to implement the behavioral observation program ($34,000), and storage for files ($10,000). The total industry implementation cost for existing plants is $(140,000)(71) = $9.94M.

(2) For all future plants (in which none of the employees will be grandfathered), the implementation costs are estimated to be $590,000 per plant. In addition to the costs noted above for existing plants, this implementation includes the cost of background investigations ($375,000), review process and appeals procedures ($36,000), increased file storage requirements ($30,000), and miscellaneous criminal checks with the FBI, etc. ($9,000). The total industry cost for future plants is ($590,000)(63) = $37.2M.

(3) The cost of operation of the access authorization system at each plant is estimated to be $300,000/year. This operating cost includes background investigations for new people as a result of employee turnover ($94,000), professional management and clerical staff ($63,000), review and appeal process ($67,000), refresher training for old supervisors ($19,000), training of new supervisors ($9,000), plan maintenance and updates ($8,000), file storage ($39,000), and criminal history checks with the FBI for new people ($2,000). The total industry cost for operation and maintenance of the access authorization system is ($0.3M/RY)(3,798 RY) or $1,140M.

The total industry cost for the SIR is $[1,140 + 9.94 + 37.2]M or $1,187M.

NRC Cost: The NRC costs for the SIR are estimated as follows:

(1) The NRC time for further development and issuance of the proposed plan is estimated to be 1.5 man-years. At a rate of $100,000/man-year, the estimated cost for this effort is $150,000.

(2) For implementation of the plan, which includes the review and modification of the utilities' plans, the NRC effort was estimated to be 1.5 man-years. For the 134 affected plants, this amounts to 0.6 man-week/plant. At a cost of $2,270/man-week, the NRC implementation cost is $182,500.

(3) NRC review of the operation and maintenance of the SIR is estimated to require 1 man-week/RY for all plants. At a cost of $2,270/man-week, the total NRC cost for operation and maintenance of the SIR is $8.6M.

The total NRC cost for the SIR is $[0.15 + 0.1825 + 8.6]M = $8.9M.

Value/Impact Assessment

Based on a public risk reduction of 16,000 man-rem, the value/impact score is given by:

$$S = \frac{16{,}000 \text{ man-rem}}{\$(1{,}187 + 8.9)M}$$

$$= 13.4 \text{ man-rem/\$M}$$

Other Considerations

It has been estimated by cognizant personnel at the NRC that the Fitness for Duty Rule will have a negative cost impact on operating licensees in the long run. The NRC estimates that initial licensee burden to develop written procedures required by the rule will be approximately 1,200 man-hours over a six-month period at a total cost between $50,000 and $75,000, if no fitness for duty program exists at the licensee's facility. While utilities such as TVA claim that alcohol abuse alone costs them approximately $18.5M annually, fitness for duty programs of the type envisioned by the Fitness for Duty Rule are expected to save costs through quicker identification of employees not fit for duty and through assisting these employees, in whom considerable resources have been invested, so that they might return to high levels of productivity Absenteeism due to alcohol-drug abuse costs U.S. industry an average of $300 annually for every worker nationwide. Alcohol drug-abusers lose an additional 25% of their productive time when on the job, at an average annual cost to U.S. industry of approximately $2,900 per abuser. The total annual cost to U.S. industry is between $12 billion to $15 billion. Wrich, in "The Employee Assistance Program; Updated for the 1980's," Hazelden, 1980, reports that U.S. industry receives a return of $10 in decreased absenteeism, accidents, and increased productivity for every dollar it spends on fitness for duty.

CONCLUSION

Although the estimated risk reduction was 16,000 man-rem and the value/impact score only 13.4 man-rem/$M, this issue was given a HIGH priority because of its advanced state of completion.

ITEM I.A.3.4: LICENSING OF ADDITIONAL OPERATIONS PERSONNEL

DESCRIPTION

Historical Background

This TMI Action Plan item[48] seeks to upgrade the operations performance in nuclear power plants by imposing licensing requirements upon other operations personnel in addition to ROs and SROs.

Safety Significance

It is possible that, by undergoing licensing, personnel such as managers, engineers, and technicians would be better qualified and less likely to commit errors in performing their functions.

Possible Solution

A study could be undertaken to determine which, if any, personnel should be licensed. Licensing would then be required by the NRC for those additional personnel.

PRIORITY DETERMINATION

Assumptions

It was estimated that the effects of resolution of this issue would be minimal for many utilities since there are existing practices which go a long way toward ensuring that qualified and trained individuals are in the responsible positions. It was assumed that additional licensing requirements would produce some improvement by assisting in the screening of potentially poor performers from the operations staff. The net effect was estimated to be equivalent to a 2% reduction in human error rates for reactor operators and maintenance personnel.[64]

Frequency Estimate

Based on the 2% reduction in human error rate, the Oconee 3 (representative PWR) risk equation parameters were adjusted. All Accident Sequences except V were assumed to be affected and all Release Categories were affected. The reduction in core-melt frequency for Oconee 3 was calculated to be 1.4×10^{-6}/RY. The reduction in core-melt frequency for Grand Gulf 1 was then calculated by assuming that the fractional core-melt frequency reduction for the representative BWR will be equivalent to the fractional reduction for the PWR. Therefore, since the Oconee 3 fractional reduction was 0.017, the core-melt frequency reduction for Grand Gulf 1 was calculated to be 6.3×10^{-7}/RY.

Consequence Estimate

The corresponding reduction in public risk for Oconee 3 was calculated to be 2.4 man-rem/RY and the public risk reduction for Grand Gulf 1 was calculated to be 2.7 man-rem/RY.

The risk reduction for each type of plant is given as follows:

PWRs: (28.5 yrs)(95 reactors)(2.4 man-rem/RY) = 6.5×10^3 man-rem
BWRs: (27 yrs)(49 reactors)(2.7 man-rem/RY) = 3.6×10^3 man-rem

Therefore, the total risk reduction for this issue is 1.01×10^4 man-rem.

Cost Estimate

Industry Cost: It was assumed that the required additional effort to license the majority of the operations personnel at a plant would be roughly equivalent to the current licensing efforts for ROs and SROs. This was estimated to be $250,000/plant. For operation, industry would have to provide new training staff, staff time for training and exams, and administration. This was estimated to be $50,000/RY. Therefore, the total industry cost is $250M.

NRC Cost: To implement this requirement, the NRC would have to prepare qualification criteria, licensing exams, and procedures. This would be a major undertaking. The NRC costs for implementation were estimated to be in the range of $20M to $50M. For analysis purposes, $35M was used. To operate with the new licensing requirements, it was estimated that the NRC would need 50 additional staff members at a total cost of $5M/year. To perform the annual operational needs of the program, funds would be needed for travel, publications, etc. This was estimated to be an additional $2M/year. Therefore, the total NRC cost is approximately $240M.

Value/Impact Assessment

Based on a total public risk reduction of 10,100 man-rem, the value/impact score is given by:

$$S = \frac{10,100 \text{ man-rem}}{\$(240 + 250)\text{M}}$$

$$= 20 \text{ man-rem/\$M}$$

Uncertainty

Because the estimate of the value/impact score relies heavily on the estimated value of the possible reduction in human error rate, the effective improvement may vary significantly.

Other Considerations

DHFS has been pursuing this issue and the Commission has concluded[181] that licensing of managers should not be required. The other portion of the issue (i.e., licensing of other personnel--engineers, maintenance personnel, etc.) is still under study and is to be concluded in FY 1983.

CONCLUSION

Although the value/impact score was low, the potential for risk reduction was considered and this issue was given a medium priority. However, in February 1985, the staff determined that there was insufficient evidence to support the licensing of additional plant personnel.[778] Thus, this item was RESOLVED and no new requirements were established.

ITEM I.A.3.5: ESTABLISH STATEMENT OF UNDERSTANDING WITH INPO

DESCRIPTION

As a part of the overall evaluation of the TMI incident, it was determined[48] that a statement of understanding was needed to address the mutual intent of NRC and INPO concerning the extent to which NRC should review or rely upon training, certification, and other activities of INPO. Consideration was also to be given to providing alternative mechanisms for industry to inform NRC of its general progress on needed safety reforms. It was intended that the statement of understanding would provide a basis for evaluation of any safety reforms or programs. There is no direct risk that can be attributed to this issue.

CONCLUSION

A Memorandum of Agreement[148] between INPO and NRC was issued in April, 1982. However, it did not specifically address training and certification. Following this, the EDO agreed with a revision[594] of Appendix Four to the Memorandum of Agreement (Coordination Plan for NRC/INPO Training-Related Activities) in November 1983. As a result, this Licensing Issue has been resolved.

REFERENCES

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.

88. Memorandum for All Employees from H. Denton, "Regionalization of Selected NRR Functions," June 15, 1982.

89. NUREG/CR-1750, "Analysis, Conclusions, and Recommendations Concerning Operator Licensing," U.S. Nuclear Regulatory Commission," January 1981.

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

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

148. "Memorandum of Agreement Between the Institute of Nuclear Power Operations and the U.S. Nuclear Regulatory Commission," Rev. 1, April 1, 1982.

181. SECY-82-155, "Public Law 96-295, Section 307(B), Study of the Feasibility and Value of Licensing Nuclear Plant Managers and Senior Licensee Officers," April 12, 1982.

289. NUREG/CR-2075, "Standards for Psychological Assessment of Nuclear Facility Personnel," U.S. Nuclear Regulatory Commission, July 1981.

290. NUREG/CR-2076, "Behavioral Reliability Program for the Nuclear Industry," U.S. Nuclear Regulatory Commission, July 1981.

440. Memorandum for W. Minners from D. Ziemann, "Schedules for Resolving and Completing Generic Issues," April 5, 1983.

593. SECY-84-76, "Proposed Rulemaking for Operator Licensing and for Training and Qualifications of Civilian Nuclear Power Plant Personnel," February 13, 1984.

594. Letter to E. Wilkinson (INPO) from W. Dircks (NRC), November 23, 1983.

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

778. Memorandum for W. Dircks from H. Denton, "TMI Action Item I.A.3.4," February 12, 1985.

TASK I.A.4: SIMULATOR USE AND DEVELOPMENT

The objectives of this task are as follows: (1) to establish and sustain a high level of realism in the training and retraining of operators, including dealing with complex transients involving multiple permutations and combinations of failures and errors, and (2) to improve operators' diagnostic capability and general knowledge of nuclear power plant systems.

ITEM I.A.4.1: INITIAL SIMULATOR IMPROVEMENT

ITEM I.A.4.1(1): SHORT-TERM STUDY OF TRAINING SIMULATORS

DESCRIPTION

The TMI Action Plan[48] called for a short-term study of training simulators. The purpose was to collect and develop corrections for presently identified weaknesses. A study of training simulators was undertaken and a report, NUREG/CR-1482,[299] was issued in June 1980.

CONCLUSION

This item has been RESOLVED and no new requirements were established.

ITEM I.A.4.1(2): INTERIM CHANGES IN TRAINING SIMULATORS

DESCRIPTION

The TMI Action Plan[48] stated that requirements to correct specific training simulator weaknesses should be developed based on the short-term study resulting from Item I.A.4.1(1). This item was completed with the issuance of Regulatory Guide 1.149,[439] "Nuclear Power Plant Simulators for Use in Operator Training."

CONCLUSION

This item has been RESOLVED and new requirements were established.

ITEM I.A.4.2: LONG-TERM TRAINING SIMULATOR UPGRADE

The four parts of this item have been combined and evaluated together.

DESCRIPTION

Historical Background

Nuclear power plant simulators are recognized as an important part of reactor operator training. The TMI Action Plan[48] called for a number of actions to improve simulators and their use. There is significant interaction among the simulator-related action items and clear separation is difficult.

Item I.A.4.2 has a number of components dealing with long-term upgrades. The NUREG-0660[48] description calls for research to improve the use of simulators in training operators, develop guidance on the need for and nature of operator action during accidents, and gather data on operator performance. Specific research items mentioned include simulator capabilities, safety-related operator action, and simulator experiments. The item also calls for the upgrading of training simulator standards, specifically updating of ANSI/ANS 3.5-1979. A regulatory guide endorsing that standard and giving the criteria for acceptability is also mentioned. The final portion of Item I.A.4.2 calls for a review of simulators to assure their conformance to the criteria.

A significant portion of the activities to be conducted under this action plan item has been completed. For example, ANSI/ANS 3.5 was revised and issued in 1981. The regulatory guide endorsing this standard, Regulatory Guide 1.149,[439] "Nuclear Power Plant Simulators for Use in Operator Training," as well as numerous research reports have been published.

It is clear that the regulations, the ANS standard, and the regulatory guide do not require a site-specific simulator. 10 CFR 55 states that, if a simulator is used in training, it "... shall accurately reproduce the operating characteristics of the facility involved and the arrangement of the instrumentation and controls of the simulator shall closely parallel that of the facility involved." ANSI/ANS 3.5-1981 calls for a high degree of fidelity between the simulator and the "reference plant." However, there is no requirement that the reference plant be the same facility that the personnel in training will in fact operate. Regulatory Guide 1.149[439] explicitly makes the distinction stating "... the similarity that must exist between a simulator and the facility that the operators are being trained to operate is not addressed in the guide and should not be confused with the guidance provided that specifies the similarity that should exist between a simulator and its reference plant."

The work that has been completed for Item I.A.4.2(1) includes the issuance of NUREG/CR-2353[300] (Volumes I and II), NUREG/CR-1908,[416] NUREG/CR-2598,[417] NUREG/CR-2534,[418] NUREG/CR-3092,[419] and NUREG/CR-3123.[653] This item, however, has long-range requirements calling for: (1) the review of operating experience to provide data on operator responses, and (2) the design and conduct of experiments to determine operator error rates under controlled conditions. Therefore, this item is not completed at this time. However, Items I.A.4.2(2) and I.A.4.2(3) have been completed with the issuance of Regulatory Guide 1.149.[439] Item I.A.4.2(4) concerns the long-term training simulator improvement criteria which were also established in Regulatory Guide 1.149,[439] issued in April 1981, and the criteria were initiated in FY 1982. However, the review of submittals from simulator owners for conformance with the criteria is an on-going task which is still not complete. Therefore, the outstanding portions of this issue that have yet to be completed are the continuation of simulator research and the review for conformance to acceptability criteria.

The assessment of this safety issue was conducted by PNL staff[64] with experience in reactor operator licensing, reactor operation, and general reactor safety, in consultation with General Physics Corporation. General Physics Corporation provides utility training services and is greatly experienced in reactor simulators, providing procurement and startup assistance, operation and maintenance services, and simulator modifications.

In the assessment of this issue it is necessary to acknowledge that many of the TMI action items associated with operator training are interrelated and that ranking problems become involved when an attempt is made to assess these independently. For example, the present issue relates to Items I.A.2.6(1,2,3, and 5), which deal with training improvements including the enhanced use of existing simulators, and I.A.4.1, which deals with initial simulator improvement, including short-term and interim changes in training simulators. However, it is useful to note that the final safety ranking of this issue is relatively insensitive to changes in the basic assumptions used to distinguish these inter-related issues, by the very nature of the ranking matrix. Therefore, it is possible to establish a priority ranking for this issue, despite the possible overlapping of potential benefits and costs with the other inter-related issues.

Safety Significance

Use of simulators with high fidelity to the reference plant would significantly improve operator training in dealing with abnormal conditions thereby reducing operator error. The operators' performance under accident conditions is expected to be enhanced. Thus, potential core melts would be avoided and overall core-melt frequency reduced.

Possible Solution

A possible solution would be to establish a high level of realism in the training and retraining of plant operators by developing simulators with a high degree of fidelity to the reference plant.

PRIORITY DETERMINATION

Assumptions

It was assumed that the major effect of these issues, both in terms of safety benefit and cost incurred, would be in the enhancement of the level of realism imparted by simulators. The specific modeling capabilities given under Item I.A.4.1(2) and in the specification of ANSI/ANS 3.5-1981 specify this feature.

It was assumed for the resolution to this safety issue, that in order to provide the intended level of realism, site-specific simulators would be acquired. Such simulators would be significantly more realistic when compared to the specific facilities, both in layout and operation, than existing generic simulators. In addition, they are assumed to have enchanced transient and accident modeling capabilities.

In our assessment, it was clear that provision of site-specific simulators, while not explicitly required, would meet the requirements of Item I.A.4.1(2), the fidelity requirements of ANSI/ANS 3.5-1981, and the accurate reproduction requirements of 10 CFR 55. Less sweeping simulator enhancements might also fulfill these requirements but would have to be decided on a case-by-case basis. Therefore, for risk, dose, and cost estimates we assumed the enhancement would be effected by the introduction of site-specific simulators.

The public risk reduction (and occupational dose reduction due to accident avoidance) are associated with the reduction in operator error expected to result from the training and requalification of operators on improved simulators. Inasmuch as any studies relating human error rates to the realism of simulator training are not available, this assessment will be based primarily on PNL engineering judgment. Therefore, it is estimated that a reduction in operator error rates of 30% will result from the resolution of this safety issue. This sole-value estimate implies that for specific instances the improvement could be much greater but the 30% reduction is used as an estimate of the average improvement for the purposes of calculation.

The number of plants and the average remaining lifetimes are taken as 90 plants and 28.8 yrs for PWRs and 44 plants and 27.4 years for BWRs. The plants selected for analysis are the Oconee 3 as representative of the PWRs and Grand Gulf as representative of the BWRs. (It is assumed that the fractional risk and core-melt frequency reductions for Grand Gulf will be equivalent to those for the PWR which is calculated directly.)

The dose calculations are based on a reactor site population density of 340 people per square mile and a typical midwest meteorology is assumed.

Frequency Estimate

All release categories are affected by the resolution of this issue. The calculated core-melt frequencies are 8.2×10^{-5}/RY for PWRs and 3.7×10^{-5}/RY for BWRs. The reduction in these frequencies, based on the 30% reduction estimated for operator error, is 1.3×10^{-5}/RY for PWRs and 5.9×10^{-6}/RY for BWRs.

Consequence Estimate

The resulting total reduction in public risk is 150,000 man-rem. The estimated reduction in occupational dose is 820 man-rem based on accident avoidance only since there are no implementation or maintenance dose reductions associated with resolution of this issue.

Cost Estimate

Industry Cost: The major effect of the resolution of these safety issues was assumed to be the acquisition and use of site-specific simulators. The costs to industry of such an undertaking would be substantial. It is important to recognize that if improved modelling changes were possible on existing simulators, the cost to industry would be substantially smaller. However, this is not clear at this time and it is assumed that new simulators would be required. (The impact of this assumption can be weighed subsequently in the final safety priority ranking. The assumption can be reevaluated at that time for any appropriate modifications.)

Assuming that new simulators would be required, the principal industry costs for implementation of this safety issue would be the purchase of the simulators and provision of the new training materials. The capital cost of a simulator is estimated to be $7M. The provision of training materials is estimated to be equivalent to a 7 man-year effort.

It was assumed that all reactors, both operating and planned, would be affected. However, not every reactor would require a simulator. Many reactor sites have two or more reactors located together. If these reactors are sufficiently similar, a single simulator could serve them. Examining the list of 134 operating and planned power reactors, it was estimated that 62 additional site-specific simulators would be adequate. This assumed that 20% of the potential simulators are not required because either a site-specific simulator already exists or the plant in question is an older facility with limited lifetime remaining.

The costs for the 62 new simulators spread over 134 reactors yields \$3.2M/reactor in capital cost and 3.2 man-year/reactor to provide new training materials. The operation and maintenance of the new simulators is estimated to require 3 man-years of effort per simulator. Again, sharing the expense for 62 simulators over 134 reactors yields 1.4 man-years/reactor. Industry may also experience costs stemming from participation in simulator experiments and research. However, in comparison to the costs related to new simulators, these costs would be small.

Based on these assumptions the total industry costs are obtained as follows:

(1) Safety Issue Resolution (SIR) Implementation

(a) Labor: $\left(\frac{7 \text{ man-yr}}{\text{simulator}}\right)\left(\frac{62 \text{ simulators}}{134 \text{ plants}}\right)\left(\frac{\$100,000}{\text{man-year}}\right) = \$320,000/\text{plant}$

(b) Equipment: $\left(\frac{62 \text{ simulators}}{134 \text{ plants}}\right)\left(\frac{\$7M}{\text{simulator}}\right) = \$3.2M$ per plant

Thus, the total industry cost for implementation is (134 plants) (\$320,000/plant + \$3,200,000/plant) or \$470M.

(2) Operation and Maintenance of the SIR

$$\left(1.4 \frac{\text{man-yr}}{\text{reactor}}\right)\left(\frac{\$100,000}{\text{man-yr}}\right) [(90 \text{ PWRs})(28.8 \text{ yrs}) + (44 \text{ BWRs})(27.4 \text{ yrs})]$$

$$= \$530M$$

Therefore, the total combined industry cost is \$(470 + 530)M or \$1,000M.

NRC Cost: The principal costs to the NRC are the continuation of research and the conduct of the confirmatory reviews. No additional development costs are foreseen as ANSI/ANS 3.5 is currently being revised and will necessitate a revision to Regulatory Guide 1.149.[439]

The continuing research is treated as an implementation cost. It is estimated to require one NRC man-year and \$1M in contractor support. (This includes the remaining costs associated with Item I.E.8.) The confirmatory reviews are also treated as an implementation cost and are estimated to require 4 man-weeks/simulator, or 248 man-weeks in all for the assumed 62 new simulators.

The operational review cost to the NRC is minimal. It is assumed that annually each simulator will be audited to assure that reference plant updates have been adequately represented on the simulator. Such an annual review is estimated to require 2 man-weeks/simulator or 124 man-weeks/year for all 62 new simulators assumed.

NRC costs are estimated as follows:

(1) SIR Development

There is no cost for SIR development since all work is essentially complete and a solution has been identified.

(2) SIR Implementation

(a) Continuing Research: $\frac{1 \text{ man-yr}}{134 \text{ plants}} = 0.33 \ \frac{\text{man-wk}}{\text{plant}}$

(b) Initial Simulator Reviews: $\frac{248 \text{ man-wk}}{134 \text{ plants}} = 1.9 \ \frac{\text{man-wk}}{\text{plant}}$

Based on a total NRC manpower of 2.23 man-wk/plant, the NRC manpower cost for implementation is

$$\left(\frac{2.23 \text{ man-wk}}{\text{plant}}\right) \left(\frac{\$2,270}{\text{man-wk}}\right) (134 \text{ plants}) = \$678,300$$

(c) NRC Contractor Support = $1M

Therefore, total NRC Cost for SIR Implementation is ($678,300 + $1M) or $1.7M.

(3) Review of SIR Operation and Maintenance

$$\left(\frac{2 \text{ man-wk}}{\text{simulator-yr}}\right) \left(\frac{67 \text{ simulators}}{134 \text{ plants}}\right) \left(\frac{\$2,270}{\text{man-wk}}\right) = \$2,100/\text{RY}$$

The total NRC cost for review of SIR operation and maintenance for all affected plants is [(90 PWRs)(28.8 yr) + (44 BWRs)(27.4 yrs)]($2,100/RY) = $8M. Thus, the total NRC cost is $(1.7 + 8)M or $9.7M.

Therefore, total industry and NRC cost for the SIR is $(1,000 + 9.7)M or $1,010M.

Value/Impact Assessment

Based on a public risk reduction of 150,000 man-rem, the value/impact score is given by:

$$S = \frac{150,000 \text{ man-rem}}{\$1,010\text{M}}$$

$$= 148.7 \text{ man-rem/\$M}$$

CONCLUSION

Based on the estimated risk reduction of 150,000 man-rem and the value/impact score of approximately 150 man-rem/$M, the safety priority ranking of this issue would be HIGH. In view of the large estimated risk reduction, this safety priority ranking is essentially unaffected by any reasonable uncertainties in the cost estimates.

ITEM I.A.4.2(1): RESEARCH ON TRAINING SIMULATORS

This item was evaluated in Item I.A.4.2 above and was determined to be HIGH priority.

ITEM I.A.4.2(2): UPGRADE TRAINING SIMULATOR STANDARDS

This item was evaluated in Item I.A.4.2 above and was determined to be RESOLVED with the issuance of Regulatory Guide 1.149[439] and new requirements were established.

ITEM I.A.4.2(3): REGULATORY GUIDE ON TRAINING SIMULATORS

This item was evaluated in Item I.A.4.2 above and was determined to be RESOLVED with the issuance of Regulatory Guide 1.149[439] and new requirements were established.

ITEM I.A.4.2(4): REVIEW SIMULATORS FOR CONFORMANCE TO CRITERIA

This item was evaluated in Item I.A.4.2 above and was determined to be a high priority issue. However, following the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issue HF01.3.3.

ITEM I.A.4.3: FEASIBILITY STUDY OF PROCUREMENT OF NRC TRAINING SIMULATOR

DESCRIPTION

The description of this safety issue in NUREG-0660[48] is as follows:

> "In addition to the increased use of industry simulators for training of NRC staff (notably, the work by OIE with the TVA training center simulators), a feasibility study of the lease or procurement of one or more simulators to be located in the NRC headquarters area will be performed. These simulators would be used in familiarizing the NRC staff with reactor operations, in assessing the effectiveness of operating and emergency procedures and in gathering data on operator performance. The study will include development of specifications, development of procurement and commissioning schedules, estimation of costs, and comparison with other methods of providing such training for NRC personnel."

Technical studies[262,263,264] that have been performed by BNL on this issue have indicated that existing simulators have significant modelling limitations. It was established that the capability of existing simulators was not acceptable at any but near-normal operating conditions, and that the lack of technical capability during two-phase conditions was significant. These results have an adverse effect on the feasibility of a training simulator for the NRC staff.

The intent of this issue is to improve the NRC staff's familiarization with reactor operations. The study is an effort to establish the feasibility of procuring an NRC training simulator. The resolution of this issue has no direct bearing on any public risk reduction and, therefore, it is concluded that this issue is a licensing issue.

CONCLUSION

This Licensing Issue has been resolved.

ITEM I.A.4.4: FEASIBILITY STUDY OF NRC ENGINEERING COMPUTER

DESCRIPTION

The description of this safety issue in NUREG-0660[48] is as follows:

> "The purpose of this study is to fully evaluate the potential value of and, if warranted, propose development of an engineering computer that realistically models PWR and BWR plant behavior for small break LOCA and other non-LOCA accidents and transients that may call for operator actions. Final development of the proposed engineering computer will depend on a number of research efforts. Risk assessment tasks (interim reliability evaluation program, or IREP, for example) to define accident sequences covering severe core damage will also provide the guidelines for the experimental and analytical research programs needed to improve the diagnostics and general knowledge of nuclear power plant systems. The programs will assist the development and testing of fast running computer codes used to predict realistic system behavior for these multiple accident studies. These codes will provide the basic models for use in the improved engineering computer as well as the capability for NRC audit of NSSS analyses."

The current status of this issue is that a report on the review of PWR simulators was completed and issued by BNL.[262] A final report on BWR simulators was also completed by BNL.[263]

Work on Plant Analyzers is continuing at BNL, INEL, and LASL. The RES staff believes that the Plant Analyzers (Engineering Computer) will be helpful in uncovering potential operational safety problems in LWRs, caused by operator errors or equipment malfunctions, which will lead to risk reductions through increased operator awareness, improved procedures, and equipment redundancy.

The Plant Analyzer is not a design tool but rather an aid to the NRC staff in performing an audit function in the licensing process. Thus, this issue will not result in a direct reduction in public risk and, therefore, is considered a licensing issue.

CONCLUSION

This item is a Licensing Issue.

REFERENCES

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.

262. BNL/NUREG-28955, "PWR Training Simulator and Evaluation of the Thermal-Hydraulic Models for Its Main Steam Supply System," Brookhaven National Laboratory, 1981.

263. BNL/NUREG-29815, "BWR Training Simulator and Evaluation of the Thermal-Hydraulic Models for Its Main Steam Supply System," Brookhaven National Laboratory, 1981.

264. BNL/NUREG-30602, "A PWP Training Simulator Comparison with RETRAN for a Reactor Trip from Full Power," Brookhaven National Laboratory, 1981.

299. NUREG/CR-1482, "Nuclear Power Plant Simulators: Their Use in Operator Training and Requalification," U.S. Nuclear Regulatory Commission, August 1980.

300. NUREG/CR-2353, "Specification and Verification of Nuclear Power Plant Training Simulator Response Characteristics," U.S. Nuclear Regulatory Commission, 1982.

416. NUREG/CR-1908, "Criteria for Safety-Related Nuclear Power Plant Operator Actions: Intitial Pressurized Water Reactor (PWR) Simulator Exercises," U.S. Nuclear Regulatory Commission, September 1981.

417. NUREG/CR-2598, "Nuclear Power Plant Control Room Task Analysis: Pilot Study for Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, July 1982.

418. NUREG/CR-2534, "Criteria for Safety-Related Nuclear Power Plant Operator Actions: Initial Boiling Water Reactor (BWR) Simulated Exercises," U.S. Nuclear Regulatory Commission, November 1982.

419. NUREG/CR-3092, "Criteria for Safety-Related Nuclear Power Plant Operator Actions: Initial Simulator to Field Data Calibration," U.S. Nuclear Regulatory Commission, February 1983.

439. Regulatory Guide 1.149, "Nuclear Power Plant Simulators for Use in Operator Training," U.S. Nuclear Regulatory Commission, April 1981.

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

653. NUREG/CR-3123, "Criteria for Safety-Related Nuclear Power Plant Operator Actions: 1982 Pressurized Water Reactor (PWR) Simulator Exercises," U.S. Nuclear Regulatory Commission, June 1983.

TASK I.B: SUPPORT PERSONNEL

TASK I.B.1: MANAGEMENT FOR OPERATIONS

The objectives of this task are as follows:

(1) To improve licensee safety performance and ability to respond to accidents by upgrading the licensee groups responsible for radiation protection and plant operation in such areas as staff size; education and experience of staff members; plant operating and emergency procedures; management awareness of, and attention to, safety matters; and numbers and types of personnel available to respond to accidents.

(2) To improve licensee safety performance by establishing a full-time, dedicated, onsite safety engineering staff and providing, along with the concurrent dissemination of information to plant personnel, an integrated program for the systematic review of operating experience.

ITEM I.B.1.1: ORGANIZATION AND MANAGEMENT LONG-TERM IMPROVEMENTS

DESCRIPTION

Historical Background

This issue[48] deals with implementation of long-term organization and management improvements. The overall objective of this item is to "improve licensee safety performance and ability to respond to accidents by upgrading licensee groups responsible for radiation protection and plant operation. The areas to be upgraded include: (1) staff size; (2) education and experience of staff members; (3) plant operating and emergency procedures; (4) management awareness of, and attention to, safety matters; and (5) numbers and types of personnel available to respond to accidents." The evaluation of this issue includes the consideration of Item II.J.3.1.

To assess this safety issue, SPEB consulted with PNL as well as with NRR and RES personnel working on developing the management, organization, and staffing regulatory positions. The PNL personnel have expertise in general management, utility and nuclear plant management, reactor operations, reactor operation licensing, and general reactor safety areas. The technical analysis for this issue was provided by PNL.[64]

Safety Significance

The safety significance of this issue is the potential for accidents resulting from some measure of human error in operating a nuclear plant that may be avoidable by the resolution of this issue.

Possible Solutions

Proper management and organization will improve administration, control, prevention, coordination both within and among all key organizational components of the plant, including those located offsite. The management involved and their staff will be better qualified and trained and the staff will be increased. The management and organization will be better-prepared for both normal operations and emergency situations.

Resolution of this safety issue is assumed to involve the following:

(1) Each utility (licensee/applicant) will be required to submit a new proposed organization and management plan which will be reviewed by the NRC, including a site review. No additional management staff will be required, but the qualifications and training of the management staff and the organization effectiveness will be improved substantially at most plants.

(2) Up to 14 additional people will be required to be added to the staff depending on the plant. These people will be maintenance (~9), health physics and chemistry (~3) and training (~2) personnel. Not included are staff to man a plant-specific simulator, if required by the NRC (this was considered under Item I.A.4.1).

It is anticipated that 25% of the plants will require no staff additions, 50% will require only 8 people, and 25% will require all 14 people. Thus, on the average, a plant would require 7 additional staff members.

(3) The OIE staff at NRC will perform annual assessments to assure each utility is satisfactorily meeting NRC management and organization requirements as identified in the initial plant review.

(4) Regulatory Guides 1.33[225] and 1.8[226] will be revised and issued, along with other appropriate regulatory guidance, to define requirements in this area.

(5) Implementation of this safety issue at all operating plants and for plants applying for an operating license is assumed to begin in FY 1984 with all plants covered by mid-FY 1985. This includes annual followup assessments under way in FY 1985.

PRIORITY DETERMINATION

Assumptions

The major benefit from resolution of this safety issue will be reduction in human errors (operators and maintenance personnel) resulting in lower public risk. This applies to the remaining operating life of all nuclear power plants (142), currently operating and under construction, subsequent to implementation of the solution in 1985, which is approximately 26 years.

The PNL staff estimated that the proper actions could potentially result in a 20% reduction in human errors at a nuclear plant. However, many of the plants (assumed to be 25%) are already well-managed and organized. These would see no further improvement. Another 50% would obtain only half the benefit and the remaining 25% would obtain the full benefit. An average value of 10% for reduction of human errors is anticipated for the nuclear industry at large.

Frequency Estimate

All accident sequences, except an interfacing system LOCA, would be affected. Reducing the human error rate by 10% is calculated to decrease the frequency of core-melt in Oconee by 5×10^{-6}/RY. The frequency of core-melt in Grand Gulf was assumed to be reduced by the same ratio, or 2×10^{-6}/RY.

Consequence Estimate

All release categories are affected and the reduction in public risk is estimated to be 13 man-rem/RY for PWRs and 15 man-rem/RY for BWRs, based on the WASH-1600[16] estimate of release and assuming a typical midwest-type meteorology and an average population density of U.S. reactor sites of 340 people per square mile. Assuming 94 PWRs and 48 BWRs with an average remaining life of 26 years after this issue is implemented in 1985, the total public risk reduction is 50,400 man-rem.

Cost Estimate

Industry Cost: The major cost of resolving this safety issue is that associated with possible additional staffing required at a nuclear plant. Both BWRs and PWRs would be affected equally. Specifically, industry costs associated with this issue are expected to be as follows:

(1) An average of 7 people/plant is used in the calculation of industry labor for operation and maintenance.

(2) Approximately 2 man-years of effort for "intermediate case" plants would be required for preparing the initial management plan and reviewing it with the NRC. (Triple that for "worst case" plants and half that for "best case" plants). An average of 2.75 man-years/plant is used in the calculation of industry labor for implementation.

(3) Approximately 1 man-month of utility effort would be required at each plant in supporting the annual NRC management assessment of the solution.

The total industry costs calculated by PNL[64] were $33M for implementation and $2.27M for operation and maintenance.

NRC Cost: NRC costs associated with resolving this safety issue are expected to be as follows:

(1) Approximately 22 man-years of effort by NRR and RES to develop the long-term regulatory position on management and organization after FY-1982.

(2) Approximately 2 man-years to write, obtain, and issue comments on revised and new regulatory guides. The major development effort behind these guides is included in (1) above.

(3) Approximately 5 man-months to review the initial management and organization plan proposed for each plant. This includes time for the site visit and assessment report.

(4) Approximately 0.5 man-months to perform an annual assessment of the solution at each plant.

The total NRC cost calculated[64] by PNL was approximately \$30.8M.

Thus, the total cost associated with the resolution of this issue is \$(33 + 2.27 + 30.8)M or \$66.07M.

Value/Impact Assessment

Based on the total public risk reduction of 50,400 man-rem, the value/impact score is given by:

$$S = \frac{50{,}400 \text{ man-rem}}{\$66.06\text{M}}$$

$$= 763 \text{ man-rem/\$M}$$

Other Considerations

There would be some reduction in occupational risk primarily from lowering occupational exposure due to fewer unplanned outages caused by human error. Maintenance staffs are primarily impacted; however, both operating and maintenance staffs will benefit from avoidance of major accidents.

The potential for exposure reduction is expected to be about 10% for those 25% of "worst case" plants, half that for the 50% of "intermediate case" plants, and none for the 25% of "best case" plants. An average value of 5% is used in the calculations which follow. It is estimated that 300 to 500 man-rem of occupational exposure occur annually at a typical facility. If we assume 400 man-rem as a best estimate, the 5% reduction results in an occupational dose reduction of 20 man-rem/plant-yr. For 142 plants with an average remaining lifetime of approximately 26 years, the total occupational risk reduction from this source is approximately 75,000 man-rem.

The industry accident avoidance cost was estimated by PNL[64] to be \$26.2M.

CONCLUSION

The potential public risk reduction is relatively large (50,400 man-rem) and the potential for occupational risk reduction is also large (75,000 man-rem), if the estimate of the reduction in human error is correct. Since most of the costs are due to additional utility staff, this value/impact could be higher if a resolution were found that did not require added staff. Therefore, based on the large potential risk reduction, this issue was given a medium priority ranking.

ITEM I.B.1.1(1): PREPARE DRAFT CRITERIA

This item was evaluated in Item I.B.1.1 above and was determined to be a medium priority issue. However, following the publication of the HFPP in NUREG-0985 Revision 1,[651] this item was determined to be covered in Issues HF01.6.1 and HF01.6.3.

ITEM I.B.1.1(2): PREPARE COMMISSION PAPER

This item was evaluated in Item I.B.1.1 above and was determined to be a medium priority issue. However, following the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issues HF01.6.1 and HF01.6.3.

ITEM I.B.1.1(3): ISSUE REQUIREMENTS FOR THE UPGRADING OF MANAGEMENT AND TECHNICAL RESOURCES

This item was evaluated in Item I.B.1.1 above and was determined to be a medium priority issue. However, following the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issues HF01.6.1 and HF01.6.3.

ITEM I.B.1.1(4): REVIEW RESPONSES TO DETERMINE ACCEPTABILITY

This item was evaluated in Item I.B.1.1 above and was determined to be a medium priority issue. However, following the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issues HF01.6.1 and HF01.6.3.

ITEM I.B.1.1(5): REVIEW IMPLEMENTATION OF THE UPGRADING ACTIVITIES

OIE routinely develops and issues inspection procedures which address new or revised regulations and requirements.[441] Thus, this item has been RESOLVED and no new requirements were established.

ITEM I.B.1.1(6): PREPARE REVISIONS TO REGULATORY GUIDES 1.33 AND 1.8

This item was evaluated in Item I.B.1.1 above and was determined to be a medium priority issue. However, following the publication of the HFPP in NUREG-0985, Revision 1,[651] the revision to Regulatory Guide 1.8[226] is now covered in Issues HF01.1.2 and HF01.3.4. The revision to Regulatory Guide 1.33[225] is now covered[652] in Subtask 1 of the work plan for Issue 75.

ITEM I.B.1.1(7): ISSUE REGULATORY GUIDES 1.33 AND 1.8

This item was evaluated in Item I.B.1.1 above and was determined to be a medium priority issue. However, following the publication of the HFPP in NUREG-0985, Revision 1,[651] the revision to Regulatory Guide 1.8[226] is now covered in Issues HF01.1.2 and HF01.3.4. The revision to Regulatory Guide 1.33[225] is now covered[652] in Subtask 1 of the work plan for Issue 75.

ITEM I.B.1.3: LOSS OF SAFETY FUNCTION

DESCRIPTION

Historical Background

This TMI Action Plan[48] item concerns regulatory action at an operating nuclear power plant in the event of human error leading to complete loss of a safety function required by the plant's Technical Specifications. The following three options specified in the TMI Action Plan[48] were considered:

1. Require licensees to immediately place the plant in the safest shutdown cooling condition following a total loss of a safety function due to personel error if a total loss of a safety function had occurred within the previous year or two. Resumption of operation would require NRC approval based on a review of the licensee's program for corrective action.
2. Use existing enforcement options (citations, fines, shutdowns).
3. Use approaches such as a point system, licensee probations, and (in the extreme) license revocations.

Safety Significance

Loss of a required safety function can lead to an increase in the probability that an event with an accident-initiating potential, should it occur, would lead to an actual major accident. This probability increase could be more or less substantial, depending on the specific function lost. The safety concern is heightened when the loss of safety function is caused by human error and this occurs more than once in a year or two. Such repeated personnel failures can bring into question whether the reliability of safety-related personnel actions at the plant involved are generally up to the standards expected and assumed in safety evaluations.

Solution

Option 2 was selected as the best option that provides the latitude needed by NRC for determination whether a particular event falls under the definition of a "loss of safety function," the role of human error in causing the event, the acuteness of the risk, the urgency and nature of appropriate remedial action, conditions for resumption of operation, and such considerations as the public health-and-safety need for power at the time.[265,266,267,287,288]

With the selection of Option 2, Item I.B.1.3 of the TMI Action Plan was terminated as such, having become part of the Enforcement Policy issue (Item IV.A.2) which has been completed.[288] This item is related to improving the NRC capability to make independent assessments of safety and, therefore, is considered a licensing issue.

CONCLUSION

This Licensing Issue has been resolved.

ITEM I.B.1.3(1): REQUIRE LICENSEES TO PLACE PLANT IN SAFEST SHUTDOWN COOLING FOLLOWING A LOSS OF SAFETY FUNCTION DUE TO PERSONNEL ERROR

This Licensing Issue was evaluated in Item I.B.1.3 above and was determined to be resolved.

ITEM I.B.1.3(2): USE EXISTING ENFORCEMENT OPTIONS TO ACCOMPLISH SAFEST SHUTDOWN COOLING

This Licensing Issue evaluated in Item I.B.1.3 above and was determined to be resolved.

ITEM I.B.1.3(3): USE NON-FISCAL APPROACHES TO ACCOMPLISH SAFEST SHUTDOWN COOLING

This Licensing Issue was evaluated in Item I.B.1.3 above and was determined to be resolved.

REFERENCES

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.

225. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," U.S. Nuclear Regulatory Commission, February 1978.

226. Regulatory Guide 1.8, "Personnel Selection and Training," U.S. Nuclear Regulatory Commission, May 1977.

265. Memorandum for the Commissioners from W. Dircks, "Enforcement Policy," March 18, 1980.

266. SECY-80-139A, "NRC Enforcement Program," August 27, 1980.

267. Memorandum for R. Purple from R. Minogue, "TMI Action Plan," October 24, 1980.

287. SECY-81-600A, "Revised General Statement of Policy and Procedure for Enforcement Actions," December 14, 1981.

288. Federal Register, Vol. 47, pp. 9987-9995 "General Statement of Policy and Procedure for Enforcement Actions," March 9, 1982.

441. Memorandum for H. Denton from R. DeYoung, "Commission Paper on the Prioritization of Generic Safety Issues," April 20, 1983.

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

652. Memorandum for W. Dircks from R. DeYoung, "Elimination of Duplicative Tracking Requirements for Revision of Regulatory Guide 1.33," July 26, 1984.

TASK I.C: OPERATING PROCEDURES

The objective of this task is to improve the quality of procedures to provide greater assurance that operator and staff actions are technically correct, explicit, and easily understood for normal, transient, and accident conditions. The overall content, wording, and format of procedures that affect plant operation, administration, maintenance, testing, and surveillance will be included.

ITEM I.C.1: SHORT-TERM ACCIDENT ANALYSIS AND PROCEDURES REVISION

ITEM I.C.1(4): CONFIRMATORY ANALYSES OF SELECTED TRANSIENTS

DESCRIPTION

Historical Background

This TMI Action Plan item[48] requires confirmatory analyses of selected transients by NRR to provide the basis for comparisons with analytical methods being used by the reactor vendors. These comparisons will assure the adequacy of the analytical methods being used to generate emergency procedures. NRC has performed a limited number of confirmatory transient analyses. The rest are currently being defined.

Safety Significance

The safety significance is the reduction in operator errors and upgrading of operating systems through confirmatory analyses of selected transients by NRC/NRR. These confirmatory analyses should provide greater assurance that operator and staff actions are technically correct.

Possible Solution

Confirmatory analyses, using the best available computer codes, will provide the basis for comparisons with the analytical methods being used by the reactor vendors. These comparisons, together with comparisons to other data, will constitute the short-term verification effort to assure the adequacy of the analytical methods being used to generate emergency procedures.

PRIORITY DETERMINATION

Frequency Estimate

To evaluate this issue, PNL assumed[64] improvements in two areas. The reduction in human error rate for operators was estimated to be 7%. Other operation improvements (set points for control systems, maintenance, hardware upgrade, etc. were estimated at 4.5%. The total improvement percentages were applied to the base-case frequencies and affected release categories for both PWR and BWR type plants. The dominant accident sequences and base-case frequencies for the Oconee

(B&W) plant were used for the PWR plants. For BWR plants, Grand Gulf 1 was used as the model.

For PWR plants the base-case core-melt frequency was determined to be 8.2×10^{-5}/RY. The adjusted core-melt frequency, considering the above improvements, was determined to be 7.3×10^{-5}/RY. The result was a reduction in core-melt frequency of 9×10^{-6}/RY. For BWR plants, the base-case and adjusted core-melt frequencies were determined to be 3.7×10^{-5}/RY and 3.3×10^{-5}/RY, respectively. The reduction in core-melt frequency for BWR plants was 4×10^{-6}/RY.

Consequence Estimate

Because of the multifactor influence of the estimated improvements, all seven of the PWR release categories and all four of the BWR release categories were assumed to be affected. The potential public risk reduction for PWR plants was calculated to be 6.5×10^4 man-rem assuming 95 plants with an average remaining life of 28.5 years. The potential public risk reduction for BWR plants was calculated to be 4×10^4 man-rem, assuming 49 plants with an average remaining life of 27 years. In all cases a population density of 340 persons per square mile and typical meteorology were assumed. The total reduction in risk to the public, based on the above results, was about 1.05×10^5 man-rem.

Cost Estimate

Industry Cost: The industry cost was estimated at $61M. This estimate included: (1) an industry rate of $1,900/man-week, (2) 30 man-weeks to implement the resolution, (3) 7 man-weeks/RY for operation and maintenance, (4) 144 plants, and (5) an average remaining plant life of 28 years.

NRC Cost: The NRC cost including implementation and reviews was estimated at $2.8M.

The total industry and NRC cost was therefore estimated at approximately $64M.

Value/Impact Assessment

Based on a total public risk reduction of 1.05×10^5 man-rem and a total cost of $64M, the value/impact score is given by:

$$S = \frac{1.05 \times 10^5 \text{ man-rem}}{\$64\text{M}}$$

$$= 1{,}650 \text{ man-rem/\$M}$$

Other Considerations

Other factors which have been considered are the accident avoidance costs and the potential occupational risk reductions. The accident avoidance cost is the product of the reduction in the probability of core-melt and industry cost factors, assuming cleanup, repair, refurbishment, and replacement power cost over a 10-year period.

The total accident avoidance costs for all PWRs (95) and all BWRs (49), which includes current operating plants and those plants expected to commence operation, are estimated to be approximately $49M. Therefore, the net industry cost for this issue, when reduced by the accident avoidance costs, would be approximately $12M.

The occupational dose incurred from accident recovery is estimated at 20,000 man-rem.[64] The total occupational dose reduction due to accident avoidance, considering all PWRs and BWRs, is 600 man-rem. If we assume a 5% reduction in annual operational doses due to imposed operating guidelines and upgraded control systems, the best estimate annual operational dose reduction is 20 man-rem/RY. For all plants and all remaining plant life, the potential occupational dose reduction is 81,000 man-rem. The above estimates indicate that the potential reduction in occupation doses during normal operation is significant and further supports a high priority ranking for this issue.

CONCLUSION

Based on the value/impact score and the potential reduction in core-melt frequency, the issue would be classified as medium priority, but was given a high priority ranking because of the total public risk reduction of 105,000 man-rem. However, since the prioritization of this issue, all required work was completed,[382,383] the issue was RESOLVED, and no new requirements were established.

ITEM I.C.9: LONG-TERM PROGRAM PLAN FOR UPGRADING OF PROCEDURES

DESCRIPTION

Historical Background

The NRC effort for this TMI Action item[48] (to be led by NRR but to involve IE, SD, and RES) was to develop a long-term program plan for the upgrading of plant procedures. This plan would incorporate and expand on current efforts associated with the development, review, and monitoring of procedures. Consideration of studies to ensure clear procedures with particular emphasis on diagnostic aids for off-normal conditions were called for. The interrelationships of administrative, operating, maintenance, test, and surveillance procedures were to be considered. The topics of emergency procedures, reliability analysis, human factors engineering, crisis management, and operator training were also to be addressed.

That part of Item I.C.9 related to emergency operating procedures (EOP), has been implemented in accordance with Item I.C.1 of NUREG-0737.[98] In regard to the EOPs, SECY-82-111[151] requested Commission approval of a set of basic requirements for emergency response capability and approval for the staff to work with licensees to develop plant specific implementation schedules. A significnt amount of work on emergency operating procedures has been completed. All four NSSS vendors have submitted technical guidelines based on re-analysis of accidents and transients. These are in the final stages of review. In the area of human factors, a survey of current practices, research on EOPs, and pilot monitoring of some NTOL plants have been completed and criteria for development of EOPs were published for public comment in NUREG-0799.[191] NUREG-0899[192] was published in final form in September 1982 and incorporated resolution of comments received on NUREG-0799.[191]

The recommended requirements for EOPs,[151] which include some of these completed or nearly completed tasks, have been conditionally approved.[190]

That part of Item 1.C.9 [48] pertaining to other long-term procedures (which were not addressed in NUREG 0737[98]) require further staff effort. The priority ranking for this remaining staff effort is discussed herein.

Safety Significance

Resolution of this issue is expected to have a significant impact on plant procedures. The changes in procedures are in turn expected to improve the safety-related performance of all plant operations staff. This would apply to both routine and abnormal operating conditions.

Possible Solution

Staff actions under Item I.C.9[48] which pertain to normal and abnormal operating procedures, maintenance, test, surveillance, and other safety-related procedures are continuing. The staff effort related to the above is scheduled in three phases:

(a) Survey ongoing studies, existing procedures, and practices of related industries; assess problems; and prioritize solutions (FY 1982-1983).
(b) Prepare guidance (NUREGs, Regulatory Guides) for industry use (FY 1983-1984).
(c) Issue requirements, prepare inspection guidance, review or audit as necessary (FY 1985-1986).

PRIORITY DETERMINATION

Frequency Estimate

To estimate the change in core-melt frequency for this issue, PNL[64] assumed a human error rate reduction of 30% for operations staff. PNL also assumed that the dominant accident sequences for the Oconee (B&W) plant were representative of all PWRs, and that the fractional risk and core-melt frequency reductions were applicable to the representative BWR (Grand Gulf).

For PWRs, the base-case core-melt frequency was determined to be 7.8×10^{-5}/RY. The adjusted core-melt frequency, considering the above improvement, was determined to be 5.6×10^{-5}/RY. The result was a reduction in core-melt frequency of 2.2×10^{-5}/RY for PWRs. In the case of the BWRs, the base-case core-melt frequency was determined to be 3.5×10^{-5}/RY. The reduction in core-melt frequency for BWRs was 9.9×10^{-6}/RY.

Consequence Estimate

All seven of the PWR release categories and all four of the BWR release categories were affected by this improvement. The potential public risk reduction for PWRs was calculated to be 53 man-rem/RY, assuming WASH-1400[16] release categories, a population density of 340 persons per square mile, and typical meteorology. The reduction in public risk for the BWRs was calculated to be 64 man-rem/RY.

The total public risk reduction for all plants (90 PWRs and 44 PWRs) was 2.1×10^5 man-rem, assuming an average remaining plant life of 28 years.

Cost Estimate

Industry Cost: The industry costs were estimated at $447M. This included $67M to implement and upgrade, and $380M due to operation and maintenance.

NRC Cost: The NRC cost including implementation and reviews was estimated at $9M.

The total industry and NRC cost was therefore estimated at approximately $456M.

Value/Impact Assessment

Based on a total public risk reduction of 2.1×10^5 man-rem, the value/impact score is given by:

$$S = \frac{2.1 \times 10^5 \text{ man-rem}}{\$456\text{M}}$$

$$= 461 \text{ man-rem/\$M}$$

Other Considerations

In the analysis of this issue, PNL[64] assumed a uniform 30% improvement in human error, including maintenance, through the dominant accident sequences. The 30% improvement is expected to over-estimate reductions in maintenance outages. It is assumed that no significant reductions in maintenance outages would reduce the potential risk reduction calculated by PNL approximately 10%. These improvements transcended normal, abnormal, and emergency procedures during the event sequences as described in NUREG-0660,[48] Item I.C.9. However, the EOP concerns originally included in Item I.C.9 were separated out of Item I.C.9 and addressed in NUREG-0737.[98] Based on subsequent discussions between the NRC staff and the PNL analyst, it was agreed that the results of the dominant accident sequences would be strongly influenced by the EOPs. This situation is expected to result in little or no change to the above calculated value/impact assessment score of 461 man-rem/$M. The reason being that the smaller risk reduction that can be attributed to this issue, after the EOP effect is removed, is balanced by lower implementation cost to complete the remaining part of this issue. The beneficial reduction in core-melt frequency and public risk calculated in the PNL analysis is however significantly less when dominant effects of the improvements in the EOPs are removed from this issue. If we assume that improved EOPs will contribute approximately 75% toward reducing the core-melt frequency and public risk, the benefit (risk reduction) attributed to improvements and upgrading of the other procedures is 25% of the total benefits previously calculated. This results in a total reduction in public risk of $(0.9)(0.25)(2.1 \times 10^5)$ man-rem or 47,000 man-rem. These reductions are attributable to that part of Item I.C.9 not addressed in Item I.C.1 of NUREG-0737.[98]

CONCLUSION

The part of this issue that was clarified in Supplement 1 to NUREG-0737 (Generic Letter No. 82-33)[376] was resolved[805] with the publication of SRP[11] Section 13.5.2, Rev. 1, and Section 13.5.2, Appendix A, Rev. 0. With the exclusion of the EOPs (which are implemented in NUREG-0737[98]), this issue was given a medium priority ranking. However, with the publication of the HFPP in NUREG-0985, Revision 1,[651] Item I.C.9 was determined to be covered in Issues HF01.4.2, HF01.4.4, and HF02.

REFERENCES

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.

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.

190. Memorandum for W. Dircks from S. Chilk, "Staff Requirements-Affirmative Session, 11:50 a.m., Friday July 16, 1982," July 20, 1982.

191. NUREG-0799, "Draft Criteria for Preparation of Emergency Operating Procedures," U.S. Nuclear Regulatory Commission, July 1, 1982.

192. NUREG-0899, "Guidelines for Preparation of Emergency Operating Procedures - Resolution of Comments on NUREG-0799," U.S. Nuclear Regulatory Commission, September 3, 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.

382. Memorandum for W. Minners from R. Mattson, "Schedules for Resolving and Completing Generic Issues," January 21, 1983.

383. Memorandum for W. Dircks from R. Mattson, "Closeout of TMI Action Plan I.C.1(4), Confirmatory Analyses of Selected Transients," November 12, 1982.

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

805. Memorandum for T. Combs from H. Denton, "Revised SRP Section 13.5.2 and Appendix A to SRP Section 13.5.2 of NUREG-0800," July 17, 1985.

TASK I.D: CONTROL ROOM DESIGN

The objective of this task is to improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them.

ITEM I.D.3: SAFETY SYSTEM STATUS MONITORING

DESCRIPTION

Historical Background

This TMI Action Plan item[48] recommends that a study be undertaken to determine the need for all licensees and applicants not committed to Regulatory Guide 1.47[150] to install a bypass and inoperable status indication system or similar system.

Safety Significance

Implementation of a well-engineered bypass and inoperable status indication system could provide the operator with timely information on the status of the plant safety systems. This operator aid could help eliminate operator errors such as those resulting from valve misalignment due to maintenance or testing errors.

Possible Solutions

A study of current industry (nuclear and others) practices could be undertaken to evaluate possible methods/systems for verifying correct system alignment. In conjunction with this, a study of failures of systems due to pump or valve unavailability could be undertaken. Based on the results, a requirement to backfit or not backfit Regulatory Guide 1.47[150] (or a revision thereof) would be set forth.

PRIORITY DETERMINATION

Assumptions

If the system is integrated with the overall control room, then it could be expected that it would reduce operator error, which in turn will lower the risk associated with operation of the monitored safety systems.

For some utilities this "new" system may result in a modest but significant reduction in operator error during an emergency whereas in others the system may have no discernible effect. An average of about 2% was applied to all presently operating plants. Plants not yet licensed or undergoing licensing are committed to Regulatory Guide 1.47.[150]

In an analysis of this issue performed by PNL,[64] Oconee 3 was selected as the representative PWR. It was assumed that the fractional risk and core-melt frequency reductions for a representative BWR (Grand Gulf 1) will be equivalent to those calculated for the representative PWR.

Frequency/Consequence Estimate

The reduction in core-melt frequency ($\bar{\Delta}F$) for Oconee was calculated to be 8.7×10^{-7}/plant-yr, based on adjustment to the risk equation parameters affected by issue resolution and then a calculation of a core-melt frequency and comparison to the base core-melt frequency.

Based on a scaling calculation (see NUREG/CR-2800[64]), the frequency reduction ($\bar{\Delta}F$) for Grand Gulf was 3.9×10^{-7}/RY. The reduction in public risk was calculated (assuming WASH-1400[16] release categories, typical midwest-site meteorology, and a uniform population density of 340 people per square-mile) to be 5.9 man-rem/RY for Oconee and 7.1 man-rem/RY for Grand Gulf.

The total risk reduction for this issue was calculated to be 1.2×10^4 man-rem, based on 5.9 man-rem/RY for 47 PWRs, 7.1 man-rem/RY for 24 BWRs, and average remaining lives of 28 years and 25 years for PWRs and BWRs, respectively.

Cost Estimate

Industry Cost: Installation costs (including labor and equipment) were estimated as follows:

Equipment	Cost
(a) Cable 30 miles @ $6.00/100 Lft	$ 9,500
(b) Elec. Penetration Limitations	300,000
(c) Cable tray and additional termination	10,000
(d) Intermediate Logic Panel	100,000
(e) Control Room Alarms/Indications	10,000
Total:	$429,500

Other	Cost
(a) Design labor @ 12 man-months	$ 75,000
(b) Installation Labor = 17 man-months	100,000
(c) QA	40,000
Total:	$215,000

Therefore, the total industry implementation cost is $644,500/plant.

Maintenance of the solution by industry is estimated to require 1 man-week/plant. At a cost of $1,000/RY, this amounts to $1.9M. Therefore, the total industry cost is $48M.

NRC Cost: NRC labor for development of the resolution is estimated to be 0.5 man-year. Review and implementation of the solution is estimated to take 4 man-weeks/plant. Therefore, the total NRC cost is $0.6M.

Thus, the total cost associated with the solution to this issue is \$(48 + 0.6)M or \$48.6M.

Value/Impact Assessment

Based on a public risk reduction of 1.2×10^4 man-rem, the value/impact score is given by:

$$S = \frac{1.2 \times 10^4 \text{ man-rem}}{\$48.6M}$$

$$= 240 \text{ man-rem/\$M}$$

Uncertainty

Because the estimate of the value/impact score relies heavily on the estimated value of the possible reduction in human error, there may be wide variance in the effective improvement.

Additional Considerations

(1) To resolve this issue effectively, it should be done in conjunction with Item I.D.1 which addresses control room design review. This issue was not explicitly included in the present Commission requirement for Control Room Design (Item I.D.1) which is to be implemented in accordance with SECY-82-111[151] and a letter[376] issued to licensees of all operating plants.

(2) As another potentially significant consideration, resolution of this issue may provide a reduction in safety system unavailability due to the contribution of maintenance and testing.

(3) DHFS is presently contracting with various groups to study this issue.[152,153] These studies could better define the assumptions (for risk reduction) used in the calculation. This would then provide better data for a benefit/cost study to determine implementation.

CONCLUSION

Based on the estimated public risk reduction and the value/impact score, this issue was given a MEDIUM priority ranking.

ITEM I.D.4: CONTROL ROOM DESIGN STANDARD

DESCRIPTION

Historical Background

This issue was documented in NUREG-0660[48] and emphasized a need for guidance on the design of control rooms to incorporate human factor considerations.

Safety Significance

Control rooms and control panels which incorporate human factor considerations can greatly enhance operator performance. This could contribute to a reduction in operator error and, therefore, a potential reduction in the frequency of core-melt accidents.

Possible Solution

An NRC Regulatory Guide endorsing industry standard(s) could be developed with the intention of providing: (1) guidance for the design of control rooms and, (2) the evaluation criteria for use in the licensing process.

PRIORITY DETERMINATION

Assumptions

PNL did an assessment of this issue.[64] From the representative PWR (Oconee) and BWR (Grand Gulf), those parameters in the risk equations requiring direct operator actions were considered affected. That is, it was assumed that the probability of operator error for these parameters were decreased by 3% based on resolution of this safety issue. It was assumed that only plants to be licensed beyond 1986 would be affected.

Frequency/Consequence Estimate

The affected accident sequences and associated base-case frequencies were determined. From these frequencies, the (Affected Release Categories) base case frequencies were determined and a new base case core-melt frequency was calculated. This was 3.1×10^{-5}/RY for the PWRs and 6.1×10^{-6}/RY for the BWRs. In addition, a new base case public risk was calculated for the affected parameters: 79.1 man-rem/RY for PWRs and 40.4 man-rem/RY for BWRs. To determine a change in public risk due to issue resolution, the affected parameters were adjusted by 3% and the frequencies of the associated sequences and release categories were determined. A new overall core-melt frequency was then determined. The new core-melt frequency was 3.01×10^{-5}/RY for PWRs and 5.95×10^{-6}/RY for BWRs. Also a new public risk was then calculated: 76.9 man-rem/RY for PWRs and 39.2 man-rem/RY for BWRs.

From the above numbers, the reduction in core-melt frequency (due to issue resolution) was calculated to be 9×10^{-7}/RY for PWRs and 1.8×10^{-7}/RY for BWRs. The public risk reduction was calculated to be 2.2 man-rem/RY for PWRs and 1.2 man-rem/RY for BWRs. Therefore, the total public risk reduction, based on 10 PWRs and 5 BWRs and an average remaining life of 30 years, was calculated to be 840 man-rem.

Cost Estimate

Industry Cost: It was assumed that for those plants expected to be completed after 1990, the cost to implement the standard will be part of the basic cost. For those plants expected to be completed between 1987 and 1990, the cost to redesign the control room was estimated to be $100,000/plant. This is based on the assumption that, in all likelihood, draft standards will be available and will be used and then only minor changes will be needed. Also, it is assumed that the standards will not require significant equipment additions, but only reworking of preliminary designs. Since there are about 10 plants to be completed between 1987 and 1990, total industry cost for implementation is \$1M. No additional cost for yearly industry operation and maintenance was assumed.

NRC Cost: The NRC cost estimate was based on an assumed \$300,000 expenditure for regulatory guide development. It was assumed that additional NRC labor of about 4 man-weeks/plant would be necessary to review the modifications that would be required for the 10 plants completed between 1987 and 1990. This equals a cost of about \$9,000/plant or \$90,000 total. The total NRC cost is then \$390,000.

Thus, the total cost associated with the solution to this issue is \$(1 + 0.39)M or \$1.39M.

Value/Impact Assessment

Based on a total public risk reduction of 840 man-rem, the value/impact score is given by:

$$S = \frac{840 \text{ man-rem}}{\$1.39\text{M}}$$

$$= 600 \text{ man-rem/\$M}$$

Uncertainties

The human error reduction is not easily quantifiable: 3% was used here, but it is subject to large uncertainties.

Other Considerations

(1) The issue was assumed to affect only future plants. Present NRC guidelines in NUREG-0700[474] are to be applied to all existing plants and NTOLs.

(2) IEEE Standards are under development.

CONCLUSION

Based on the above value/impact score, this issue was given a medium priority ranking. However, with the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issue HF01.5.3.

ITEM I.D.5: IMPROVED CONTROL ROOM INSTRUMENTATION RESEARCH

ITEM I.D.5(1): OPERATOR-PROCESS COMMUNICATION

DESCRIPTION

Historical Background

This issue was documented in the TMI Action Plan[48] and focused on the need to evaluate the operator machine interface in reactor control rooms. The emphasis of this portion of the overall issue was the use of lights, alarms, and annunciators.

Safety Significance

The method of presentation of information can significantly enhance the performance of the control room operators and thereby potentially affect operator error.

Possible Solution

It was proposed that current practice and use of lights, alarms, and annunciators be reviewed to assess how well they facilitate operator-machine interaction and minimize errors. RES has studied the area of control room alarms and annunciators (through a contractor) and the results were reported in NUREG/CR-2147.[244] Based on this report, RES issued a Research Information Letter[245] (RIL-124) which provided a recommendation for further action.

CONCLUSION

This item was RESOLVED and no new requirements were established.

ITEM I.D.5(2): PLANT STATUS AND POSTACCIDENT MONITORING

DESCRIPTION

Historical Background

This issue was documented in the TMI Action Plan[48] and focused on the need to improve the ability of reactor operators to prevent, diagnose, and properly respond to accidents. The emphasis was on the information needs (i.e., indication of plant status) of the operator.

Safety Significance

In order for the operators to perform their functions it is necessary that they receive all the necessary information on the plant status. This can enhance operator performance (and therefore reduce operator error).

Possible Solution

Accident sequences should be analyzed to determine the information required to provide unambiguous indication of plant status. Specific instrumentation and ESF status monitoring needs would then be determined. PWR instrumentation requirements were analyzed in NUREG/CR-1440[241] and BWR instrumentation requirements were analyzed in NUREG/CR-2100.[242] ESF Status Monitoring requirements were also studied in NUREG/CR-2278.[243] Research Information Letter (RIL) No. 98[246] was issued in August 1980. This RIL transmitted "the results of completed research describing an improved method for analyzing accident sequences." Revision 2 to Regulatory Guide 1.97[55] was issued in December 1980. (See also Item II.F.3, "Instrumentation for Monitoring Accident Conditions.") Present plans include implementation of this guide at all plants.[151,376]

CONCLUSION

This item was RESOLVED and new requirements were established.

ITEM I.D.5(3): ON-LINE REACTOR SURVEILLANCE SYSTEM

DESCRIPTION

This item was documented in the TMI Action Plan[48] based on the work being performed by ORNL. A continuous on-line automated surveillance system was installed at Sequoyah-1 (PWR) and information has been obtained throughout the first fuel cycle.

The demonstration at Sequoyah is planned to continue through the second fuel cycle (mid-1984). A similar demonstration at an operating BWR is planned for initiation in 1984. The system has the potential to provide diagnostic information to predict anomalous behavior of operating reactors which could be used to maintain safe conditions.

Noise surveillance and diagnostic techniques associated with the on-line reactor surveillance system have shown their safety significance and the results of the research have been and are being used by NRC in regulatory activities as discussed below. Monitoring of neutron noise in BWRs was used to detect and monitor the impacting of instrument tubes against fuel boxes. The technique was used by NRC and its consultants to verify that partial power operation was safe until the next scheduled fuel outages for some 10 BWRs. Pressure noise surveillance was used at TMI-2 to monitor and guide degassification of the primary loop. Recently, the data obtained from the on-line surveillance demonstrated at Sequoyah-1 was used by NRC and its consultants in the assessment of loose thermal shields in Oconee Units 1, 2, and 3. In yet another example, NRR is currently using results of this research in BWR stability determinations associated with regulatory actions pertaining to Dresden.

CONCLUSION

Based on the ongoing programs, we conclude that the technical resolution of this issue has been identified.

ITEM I.D.5(4): PROCESS MONITORING INSTRUMENTATION

DESCRIPTION

This item was documented in the TMI Action Plan[48] and was to explore the feasibility of using new concepts for measuring certain reactor parameters. A directly related issue, Item II.F.2 in NUREG-0737,[98] mandated that industry develop and implement PWR liquid level detection systems. NRC evaluated a number of systems at the LOCA experiment facilities at ORNL and INEL.

CONCLUSION

This item has been RESOLVED and no new requirements were established.

ITEM I.D.5(5): DISTURBANCE ANALYSIS SYSTEMS

DESCRIPTION

Historical Background

This issue was documented in the TMI Action Plan[48] and its objective was to explore advanced disturbance analysis systems for possible application to nuclear power plants.

Safety Significance

If potential transient events could be anticipated and terminated earlier and if operator response could be enhanced, then the core-melt frequency may be reduced. Advanced disturbance analysis systems could possibly provide the capabilities to achieve this.

Possible Solution

The purpose of this item was to assess the need, feasibility, and adequacy of advanced disturbance analysis systems. EPRI is presently doing research in this area.

PRIORITY DETERMINATION

Assumptions

To evaluate this item, we assumed that the advanced disturbance analysis system would include the implementation of a continuous on-line surveillance system, as discussed in Item I.D.5(3). [A liquid level detection system was assumed available because it is already required - Items I.D.5(4) and II.F.2.]

In a PNL assessment of this issue,[64] it was decided that a risk reduction could be estimated by assuming a reduction in operator errors. Operator error was assumed to be reduced by 2% due to the implementation of this additional operator aid. Also, a reduction in the number of transients requiring shutdown was assumed based on the potential that the operators will be able to terminate some transients before the need for shutdown. Reduced transient frequencies were calculated based on a recent EPRI analysis.[307] The basis for choosing the transients was that either the detection time leading up to the transient or the time from the transient occurrence to shutdown was perceived to be longer than 30 minutes, enabling the advanced diagnostic system to diagnose the problem and provide possible solutions for the operator.

Furthermore, for purposes of this study, it was assumed that the operator could only respond with actions to 80% of the transients listed that would occur during the remaining lifetimes of the subject plants. Of the 80%, only 25% of the operator's actions was assumed to prevent the need for shutdown. The average plant shutdown was assumed to last 0.75 day. Therefore, reduction in unscheduled outages is calculated as follows:

PWR: (4.63 transients/RY)(0.80)(0.25)(0.75 day/shutdown) = 0.69 day/RY

BWR: (5.20 transients/RY)(0.80)(0.25)(0.75 day/shutdown) = 0.78 day/RY

Frequency Estimate

The parameters which included direct operator action were adjusted based on the 2% operator error reduction. In addition, the reduced transient frequency calculated from above were divided by the total PWR and BWR transient frequencies (i.e., 9.8 events/RY for PWRs and 8.9 events/RY for BWRs) to give a percent transient reduction. Then the parameters for transients (T_2 and T_3 for PWRs and T_{23} for BWRs) were adjusted.

Combining the reduction in operator error and the reduction in transient frequencies, the reductions in core-melt frequencies are 4.4×10^{-6} event/RY for PWRs and 2.6×10^{-5} event/RY for BWRs.

Consequence Estimate

The associated per-plant reduction in public risk was calculated (assuming 340 people per square mile) to be 12 man-rem/RY for PWRs and 18 man-rem/RY for BWRs. Assuming 90 PWRs and 44 BWRs with remaining lives of 28.8 and 27.4 years, respectively, the total public risk reduction was calculated to be 53,000 man-rem.

Cost Estimate

Industry Cost: For the advanced diagnostic system, implementation costs (hardware and installation), were estimated to be $1.5M/plant. The on-line surveillance system was estimated to cost $125,000/plant for hardware and $375,000/plant for installation. For 134 plants, the total implementation cost is approximately $270M.

Industry labor for operation and maintenance was estimated to be about 10 man-weeks/RY beyond that currently required for control room instrumentation. Therefore, this cost would be:

(10 man-wk/RY)($2,270/man-wk)(134 plants)(30 years) = $91M.

Therefore, the total industry cost was estimated to be $360M.

NRC Cost: NRC costs for issue resolution were considered to be relatively minor ($2M), based on the assumption that EPRI would continue to do the major portion of the research on this issue. NRC costs for labor to approve and monitor hardware changes to backfit plants were based on an average of 4 man-wk/backfit per plant. This cost is given by:

(4 man-wk/backfit plant)($2,270/man-wk)(71 plants) = $650,000.

Therefore, the total NRC cost is $2.65M.

Thus, the total cost associated with the resolution of this issue is $(360 + 2.65)M or $362.65M.

Value/Impact Assessment

Based on a total public risk reduction of 53,000 man-rem, the value/impact score is given by:

$$S = \frac{53{,}000 \text{ man-rem}}{\$362.65M}$$

$$\cong 150 \text{ man-rem/\$M}$$

Uncertainty

The assumed benefits of resolution and cost for implementation of this safety issue are extremely hard to quantify because of the uncertain nature of possible future developments in this area.

Other Considerations

(1) If it is assumed that replacement power costs $300,000/day and, as previously calculated, the issue resolution will reduce down time by 0.69 day/RY for PWRs and 0.78 day/RY for BWRs, the industry cost saving is:

($300,000/day)[(0.69 day/RY)(90 plants)(30 years) + (0.78 day/RY) (44 plants)(30 yrs)] = $870M

Combining this with the industry costs (implementation and operation) would show an industry saving of about $500M. Including accident avoidance costs would further increase this saving.

(2) EPRI is doing research in this area which is being followed by NRC.

CONCLUSION

The calculated value/impact score barely indicated a medium priority, but the potential saving in plant downtime would make the implementation of the solution to this issue much more cost-effective. Based on these factors and the additional factor that required NRC resources were minimal, this issue was given a medium priority ranking. However, with the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issue HF01.5.4.

ITEM I.D.6: TECHNOLOGY TRANSFER CONFERENCE

DESCRIPTION

NRC and IEEE jointly sponsored a technology transfer conference in January, 1980. The conference was entitled "Advanced Electrotechnology Applications to Nuclear Power Plants," and had as its objective to consider the practicality of applying advanced technologies from other industries (e.g. aerospace, defense, aviation) to the nuclear power industry.

During the conference, eight parallel workshops were held including: Systems Management Techniques; Reliability Engineering; Risk Assessment; Software Reliability Verification and Validation; Smart Instrumentation; Operational

Aids-Command Control and Communications; Education, Training and Simulators; and Simulation and Analysis. The conference report[306] was issued in June 1980. This item is related to increasing knowledge and understanding of safety issues and, therefore, is considered a licensing issue.

CONCLUSION

This Licensing Issue has been resolved.

REFERENCES

48. NUREG-0660, "NRC Action Plan Item 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.

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

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

150. Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems," U.S. Nuclear Regulatory Commission, May 1973.

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

152. NUREG/CR-2417, "Identification and Analysis of Human Errors Underlying Pump and Valve Related Events Reported by Nuclear Power Plant Licensees," U.S. Nuclear Regulatory Commission, February 1982.

153. "Safety System Status Monitoring: Draft Report on Current Industry Practice," Battelle Pacific Northwest Laboratories, June 1982.

241. NUREG/CR-1440, "Light Water Reactor Status Monitoring During Accident Conditions," U.S. Nuclear Regulatory Commission, May 1980.

242. NUREG/CR-2100, "Boiling Water Reactor Status Monitoring During Accident Conditions," U.S. Nuclear Regulatory Commission, May 1981.

243. NUREG/CR-2278, "Light Water Reactor Engineered Safety Features Status Monitoring," U.S. Nuclear Regulatory Commission, October 1981.

244. NUREG/CR-2147, "Nuclear Control Room Annunciators," U.S. Nuclear Regulatory Commission, October 1981.

245. RIL-124, "Control Room Alarms and Annunciators," U.S. Nuclear Regulatory Commission.

246. RIL-98, "Light Water Reactor Status Monitoring During Accident Conditions," U.S. Nuclear Regulatory Commission, August 18, 1980.

306. IEEE Catalog No. TH0073-7, "Record of the Working Conference on Advanced Electrotechnology Applications to Nuclear Power Plants, January 15-17, 1980, Washington, D.C." 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.

474. NUREG-0700, "Guidelines for Control Room Design Reviews," U.S. Nuclear Regulatory Commission, September 1981.

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

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] has 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 includes the consideration of Issue 5 listed in Section 1 of this report.

Solution

"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. (There is a task presently underway to define the applicability of 10 CFR 50, Appendix B to 10 CFR 50, Appendix A required equipment)."[48]

PRIORITY DETERMINATION

The principal benefits to be derived from the expanded QA list is the knowledge that adequate guidance is provided the plant owner to establish quality assurance programs and requirements which are commensurate with the safety importance of the structure, system, and components as determined from completed risk assessments. Currently, the quality assurance 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 the plant owners QA list which previously were excluded but will also aid in clarifying the quality assurance 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 quality assurance level of effort. However, it appears reasonable to assert that a significant reduction in public risk could be achieved for these plants in which the quality assurance 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 quality assurance programs of these plants have actually operated.

Cost Estimate

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

NRC Cost: The NRC costs have been 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 item, it would appear reasonable that the assurance afforded for safer operation would validate the HIGH priority assigned.

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 quality assurance 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 contruction 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.

Resolution of this issue assumes that these criteria are 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 eleven items listed in the possible solutions section for improving quality assurance.

It appears that the intent of this item is to provide more explicit and detailed criteria concerning the elements which are, in general, found in well conducted quality assurance programs. It is inferred that providing these more detailed criteria will, in and of themselves, result in the establishment of quality assurance programs of the caliber desired. Such programs it is believed will result in the detection of deficiencies in design, construction, and operation. But, to do this task adequately, the quality assurance program must be independent of the performing organization; further, the qualitiy assurance 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 the plant management as regards the benefits to be derived from such a QA program. Those utilities which place a high importance rating upon quality assurance 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 which 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."

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 Standard Review Plan.[11]

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.

CONCLUSION

It is believed that the issue of quality assurance 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 are rated 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," U.S. Nuclear Regulatory Commission.

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.

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

TASK II.B: CONSIDERATION OF DEGRADED OR MELTED CORES IN SAFETY REVIEW

The objective of this task is to enhance public safety and reduce individual and societal risk by developing and implementing a phased program to include, in safety reviews, consideration of core degradation and melting beyond the design basis.

ITEM II.B.5: RESEARCH ON PHENOMENA ASSOCIATED WITH CORE DEGRADATION AND FUEL MELTING

ITEM II.B.5(1): BEHAVIOR OF SEVERELY DAMAGED FUEL

Items II.B.5(1) and II.B.5(2) have been combined and evaluated together.

DESCRIPTION

Historical Background

"For a number of key severe accident sequences, there are critical phenomenological unknowns or uncertainties that impact containment integrity assessments and judgments regarding the desirability of certain mitigating features. The phenomena fall into three broad categories: (1) the behavior of severely damaged fuel, including oxidation and hydrogen generation; (2) the behavior of the core melt in its interaction with water, concrete, and core-retention materials; and (3) the effect of potential hydrogen burning and/or explosions on containment integrity. Steam explosions will also be considered in this category. Previous work in these several areas has received less attention, since these areas relate to accidents beyond the design basis [of power plants]... RES [is] conducting major programs to support the basis for rulemaking and to confirm certain licensing decisions. Complementary efforts conducted within NRR will address specific licensing issues related to the subject research."[48]

(1) Behavior of Severely Damaged Fuel

(a) In-pile studies: Fuel behavior research will include in-pile testing to help evaluate the effects of conditions leading to severe fuel damage. Such tests are being performed in the INEL Power Burst Facility (PBF) in FY 1983 and later in the ACRR at Sandia and in the NRU reactor at Chalk River National Lab, Canada.

In the PBF (and NRU, if funding permits) RES will perform a series of in-reactor fuel experiments to determine the effect of heating and cooling rates on damage to the bundle, rod fragmentation, distortion, and debris formation. Fission product release and hydrogen generation will also be measured during the test.

Separate effects studies will be conducted on rubble beds in the ACRR at Sandia.

(b) Hydrogen studies: The objective of this work is to increase understanding of the formation of hydrogen in a reactor from metal-water reactions, radiolytic decomposition of coolant, and corrosion of metals, and to determine its consequences in terms of pressure-time histories and hydrogen deflagration of detonation. This work will also include: (1) the preparation of a compendium of information related to hydrogen as it affects reactor safety, (2) analysis of radiolysis under accident conditions, (3) a review of hydrogen sampling and analysis methods, (4) a study of the effects of hydrogen embrittlement on reactor vessel materials, and (5) a review of means of handling accident-generated hydrogen, with recommendations on improving current methods. Results of these studies were considered to support USI A-48, "Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment," and were not considered further in this issue.

(c) Studies of postaccident coolant chemistry: The RES objective in this area is the development of a relationship between fission product release and fuel failure, and the improvement of postaccident sampling and analysis techniques. This will be accomplished by the investigation of fission product release in a variety of fuel failure experiments.

(d) Modeling of severe fuel damage: The effort in this area is the development of fuel models for fuel rods operating beyond 2200°F which suffer a loss in geometry in order to compute extensive damage phenomena (such as eutectic liquid formation, fuel slumping, oxidation and hydrogen generation, fission product release and interaction with the coolant, rubble-bed particle size, extent of fuel and clad melting, and flow blockage).

(2) Behavior of Core-Melt

The RES fuel melt research program will develop a base and verified methodology for assessing the consequences and mitigation of fuel melt accidents. The program addresses the range of severe reactor accident phenomena from the time when extensive fuel damage and major core geometry changes have occurred until the containment has failed and/or the molten core materials have attained a semipermanent configuration and further movement is terminated. Studies of improvements in containment design to reduce the risk of core-melt accidents are also included.

The program is composed of integrated tasks that include scoping, phenomenological and separate effects tests, and demonstration experiments that provide results for the development and verification of analytical models and codes. These codes and supporting data are then used for the analysis of thermal, mechanical, and radiological consequences of accidents and for decisions related to requirements of design features for mitigation and performance confirmation.

The technical scope of the program includes work in the following areas: fuel debris behavior, fuel interactions with structure and soil, radiological source term, fuel-coolant interactions, systems analysis codes, and mitigation features.

Safety Significance

The results of the research programs described above will find broad application in areas such as probabilistic risk analysis, accident analysis, siting, evacuation planning, emergency procedures, code development, etc. Thus, these programs would have considerable value just as licensing improvement efforts. However, these programs do have a sufficiently well-defined scope to permit some estimates of direct safety significance.

These programs are directed at a better understanding of severely damaged and molten cores. Once a core is in this state, any safety significance has to be in the area of minimizing radioactive releases and consequent dose to the public.

Possible Solutions

As with any research program, if the ultimate result were already known, the research would not be necessary. For prioritization purposes, we will assume that means will be devised to reduce the probability of containment failure and release of activity to the environment. Nevertheless, it should be remembered that completely different approaches may suggest themselves after the results of the research programs are in.

The "classical" engineering approaches to handle degraded or melted cores are filtered vents to prevent containment overpressure and core retention devices (core catchers) to prevent containment basemat melt-through. These approaches will be used for cost estimates, but the other priority parameters are not specific to these approaches.

PRIORITY DETERMINATION

These items were originally investigated by PNL.[64] However, PNL's work considered only containment basemat melt-through. The approach presented here has been expanded to include other aspects.

We will consider the effect on a PWR with a dry containment (based at least partly on the availability of information.) It is not expected that the results for other containments or for BWRs will be greatly different, at least in the context of the uncertainty of such an analysis.

Frequency Estimate

Essentially all core melts are assumed to result in containment failure in WASH-1400.[16] To estimate the effect of being able to deal with a severely damaged core, this assumption will be relaxed.

The modes of containment failure for PWRs are usually designated by Greek letters. These definitions are:

α - Containment rupture due to a reactor vessel steam explosion.

β - Containment failure due to inadequate isolation of openings and penetrations.

γ - Containment failure due to hydrogen burning.

δ - Containment failure due to overpressure.

ε - Containment vessel melt-through.

If the research programs are successful in the sense of leading to engineering solutions, we might, based purely on judgment, envision reductions in the frequency of the various failure modes as follows:

α - 10% (little can be done about steam explosions)

β - 0% (this does not affect isolation failure)

γ,δ - 90% (venting containment should be quite effective if we know how to size the vent and what filtration is needed)

ε - 90% (should be achievable if we can design a core catcher)

Consequence Estimate

The consequences are straightforward in the sense that the consequences of each release category have been studied. However, the reduction in consequences is more difficult to assess, since the release from a molten core in a tight containment is still not zero. Instead, it depends on the containment design leak rate, the efficiency of filtration of a containment relief vent, etc. To allow for this, we will assume that the prevented releases corresponding to the α, γ, δ, and ε failure modes instead release activity corresponding to a PWR-9 release. The results of this calculation are summarized and shown in Table II.B-1.

Cost Estimate

PNL estimated the cost of a core retention device at $1.4M for a forward fit.[64] Sandia estimated the cost of a filtered containment vent to be "on the order of a few million dollars."[312] We will postulate a cost to the licensee of $10M per reactor.

PNL estimated total NRC costs at $2.3M, assuming implementation at 134 reactors.[64] In reality, implementation might take place at a far smaller number of plants, due to considerations of containment type, backfit vs. forward fit, etc. However, even if only 10 plants were affected, the NRC cost would be insignificant compared to licensee costs. Therefore, NRC costs will be neglected.

Value/Impact Assessment

For a new (forward-fit) plant (which is the most likely candidate for implementation), the public risk reduction is 1,600 man-rem. Therefore, the value/impact score is given by

$$S = \frac{1{,}600 \text{ man-rem/reactor}}{\$10\text{M/reactor}}$$

$$= 160 \text{ man-rem/\$M}$$

Table II B-1

Release Category	Frequency* $(RY)^{-1}$	% Reduction** in Frequency	ΔF $(RY)^{-1}$	R (man-rem)	ΔFR
PWR-1	5.3×10^{-8}	10%	5.3×10^{-9}	4.9×10^{6}	2.6×10^{-2}
PWR-2	6.7×10^{-6}	90%	6.0×10^{-6}	4.8×10^{6}	2.9×10^{1}
PWR-3	2.6×10^{-6}	81%	2.1×10^{-6}	5.4×10^{6}	1.1×10^{1}
PWR-4	2.1×10^{-11}	--	--	2.7×10^{6}	--
PWR-5	4.9×10^{-8}	--	--	1.0×10^{6}	--
PWR-6	6.3×10^{-7}	90%	5.7×10^{-7}	1.4×10^{5}	8.0×10^{-2}
PWR-7	3.4×10^{-5}	90%	3.1×10^{-5}	2.3×10^{3}	7.1×10^{-2}
PWR-8	8.0×10^{-7}	--	--	7.5×10^{4}	--
PWR-9	4.0×10^{-4}	--	-3.9×10^{-5}	1.2×10^{2}	-4.7×10^{-3}
			TOTAL:		4.0×10^{1}

*Because the specific containment failure mode is of interest here, the frequencies above are "unsmoothed." This is in contrast to the calculations in WASH-1400[16] which assume a 10% contribution in frequency from adjacent release categories.

**Release Category PWR-1 is made up entirely of α failures and thus is assigned a 10% reduction in frequency. Categories PWR-2, PWR-6, and PWR-7 are made up of γ, δ, and ε failures and are thus assigned 90%. Category PWR-3 contains both α and δ failures which results in a net assignment of 81%.

CONCLUSION

Based on the above, this is a HIGH priority issue.

ITEM II.B.5(2): BEHAVIOR OF CORE MELT

This item was evaluated in Item II.B.5(1) above and was determined to be a HIGH priority issue.

ITEM II.B.5(3): EFFECT OF HYDROGEN BURNING AND EXPLOSIONS ON CONTAINMENT STRUCTURE

DESCRIPTION

Historical Background

TMI Action Plan Item II.B.5 called for research into the phenomena associated with severe core damage and core melting.[48] Item II.B.5(3) deals with the effect of hydrogen burns and/or explosions on containment integrity.

Safety Significance

Whereas Items II.B.5(1) and II.B.5(2) deal with (among other things) the generation of hydrogen via radiolysis, metal-water interaction, interaction of a molten core with concrete, etc., Item II.B.5(3) is concerned with the effects on the containment of the burning and/or detonation of this hydrogen. If the containment retains its integrity, even a severe accident resulting in a damaged or molten core produces relatively low offsite consequences.

Item II.B.5(3) also includes the effect of steam explosions. Again, the emphasis here is not in preventing the explosion but, instead, is in maintaining containment integrity.

Possible Solution

Most of the work on Item II.B.5(3) has been couched in terms of a stronger containment. However, as with any research program, other solutions may surface as work progresses.

PRIORITY DETERMINATION

Item II.B.5(3) is, to a large extent, similar to USI A-48, "Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment." USI A-48 is somewhat more general in that it includes the effects of a hydrogen burn or detonation on containment penetrations and on safety systems located within the containment, not just the structural response of the containment. In addition, USI A-48 includes measures for control of the hydrogen burn and thus has preventive as well as mitigative aspects.

However, even though USI A-48 will use the results of Item II.B.5(3), Item II.B.5(3) is not subsumed in USI A-48 because (1) the scope of USI A-48 is still under discussion, and (2) Item II.B.5(3) includes steam explosions as well as hydrogen burns.

Frequency/Consequence Estimate

In WASH-1400,[16] the PWR sequences refer to steam explosion induced containment failures as "α" failures. Containment failures induced by a hydrogen burn are called "γ" failures. Sequences including these two failure modes can be found in Release Categories PWR-1, PWR-2, and PWR-3.

We will assume that the efforts of Item II.B.5(3) will result in a 90 percent reduction in the probabilities of the sequences involving these two failure modes. The results are tabulated as follows:

Release Category	α Frequency (RY^{-1})	γ Frequency (RY^{-1})	Consequences (man-rem)	0.9FR (man-rem/RY)
PWR-1	5.3×10^{-8}	--	4.9×10^{6}	0.23
PWR-2	--	7.0×10^{-7}	4.8×10^{6}	3.0
PWR-3	3.4×10^{-7}	--	5.4×10^{6}	1.7
PWR-7	-3.9×10^{-7}	-7.0×10^{-7}	2.3×10^{3}	-0.002
			TOTAL:	4.9

The PWR-7 negative contribution comes in because a molten core still gives some release, even if containment failure is prevented. Thus, we assume that the events which would have been α or γ failures instead lead to PWR-7 releases.

Over a 40-year plant lifetime, the risk reduction above corresponds to about 200 man-rem/reactor. This was calculated using the WASH-1400[16] PWR numbers which were calculated for a plant with a large dry containment. BWR pressure-suppression containments and PWR ice-condenser containments have a much smaller free volume, and thus are more susceptible to α and γ failures. Therefore, the number for these plants could well be considerably higher.

Cost Estimate

Without the results of the research, it is difficult to assess costs. A stronger containment could cost \$15M based on doubling the 3½ foot wall thickness of a (150 ft x 200 ft) structure. (Such structures cost roughly \$1,000/cubic yard of concrete.) NRC costs are likely to be negligible in comparison.

Value/Impact Assessment

Based on a total estimated risk reduction of 200 man-rem/reactor, the value/impact score is given by:

$$S = \frac{200 \text{ man-rem/reactor}}{\$15\text{M/reactor}}$$

$$= 13 \text{ man-rem/\$M}$$

CONCLUSION

The public risk estimate for this issue is significant even for dry containments. However, at this point, a cost-effective solution is difficult. Therefore, based on the above value/impact score, this issue has been assigned a MEDIUM priority.

ITEM II.B.6: RISK REDUCTION FOR OPERATING REACTORS AT SITES WITH HIGH POPULATION DENSITIES

DESCRIPTION

Historical Background

This TMI Action Plan item[48] involved "... the review of operating reactors in areas of high population density to determine what additional measures and/or design changes can and should be implemented that will further reduce the probability of a severe reactor accident and will reduce the consequences of such an accident by reducing the amount of radioactive releases and/or by delaying any radioactive releases, and thereby provide additional time for evacuation near the sites."

Risk studies were proposed for the Zion and Limerick sites, which were completed in 1981, and Indian Point, which was completed in 1982. Although risk assessments of other sites either have been, are, or will be conducted by other NRC programs e.g., National Reliability Evaluation Program (NREP), no further risk studies are presently envisioned as part of this issue. Further efforts directed towards this issue will be reviews of the analysis and the possible implementation of site-specific fixes to reduce the risk at these sites. Currently, special hearings are scheduled to review possible design changes for Indian Point. The Indian Point hearings are scheduled for fiscal year 1982. However, follow-up work in connection with the accepted fixes is foreseen subsequent to these hearings.

Safety Significance

Concern exists over the potential for above-average societal risk due to accidents at reactor sites located near regions of high population densities.

Possible Solutions

As mentioned above, hearings are currently scheduled on possible fixes at the Indian Point site to reduce the risk. At present, the actual fixes that will result from these hearings are unknown. Nevertheless, it seems reasonable to assume that fixes will be made to reduce the likelihood of the most dominant accident sequences contributing to the frequency of core-melt accidents.

PRIORITY DETERMINATION

Assumptions

Based on a review of similar RSSMAP and IREP analyses, it is assumed that two sequences contribute to a large portion (50%) of the likelihood of core-melt. It is further assumed that it will be possible to reduce the frequency of each sequence by a factor of 10.

Frequency/Consequence Estimate

Resulting from age of design and other related factors, reactors in this category may have an increased frequency of core-melt over the baseline plant (Oconee) by a factor of 5.5 and an increased exposure increase over the mean population density (340 persons per square mile) and release fractions by a factor of 3. This results in a revised baseline of the following:

$$\text{Core-Melt Frequency} = (5.5)\ (8.2 \times 10^{-5}/\text{RY}) = 4.5 \times 10^{-4}/\text{RY}$$

$$\text{Exposure Increase} = (3)\ (2.5 \times 10^{6}\ \text{man-rem}) = (7.5 \times 10^{6})\ \text{man-rem}$$

Assuming that we can reduce the dominant sequences (50% of the frequency) by a factor of 10, the revised core-melt frequency would become, $(0.55) \times (4.5 \times 10^{-4})/\text{RY} = 2.5 \times 10^{-4}/\text{RY}$.

The baseline public risk is $(4.5 \times 10^{-4}/\text{RY})\ (7.5 \times 10^{6}$ man-rem) or 3,380 man-rem/RY. The revised public risk becomes $(2.5 \times 10^{-4}/\text{RY})\ (7.5 \times 10^{6}$ man-rem) or 1,880 man-rem/RY. The resulting change in public risk is then 1,500 man-rem/RY resulting from the reduction in core-melt frequency of $2 \times 10^{-4}/\text{RY}$. Over the 27 years of plant life remaining, this would result in a total risk reduction of 40,500 man-rem/reactor.

Cost Estimate

Utility costs are estimated to be \$4M/reactor to implement the changes required to reduce the two dominant sequences. NRC costs are estimated to be \$22,000. Therefore, total implementation costs are \$4.02M/reactor.

Value/Impact Assessment

Based on a total public risk reduction of 4.05×10^4 man-rem, the value/impact score is given by:

$$S = \frac{4.05 \times 10^4 \text{ man-rem/reactor}}{\$4.02\text{M/reactor}}$$

$$= 10{,}000 \text{ man-rem/\$M}$$

Other Considerations

Another factor which can be considered in this issue is the accident avoidance cost, estimated to be approximately \$11M, a potential cost saving of \$7M considering the \$4M implementation costs.

CONCLUSION

Based on the above value/impact score, this issue was given a high priority ranking. A staff review of PRAs submitted by the affected licensees was used to identify the strengths and weaknesses of the various plants and to assess the risk associated with their operation. A special adjudicatory proceeding was held from 1982 to 1983 during which time the issues regarding continued operation and risks of the Indian Point plants were heard. Following these hearings, the Commission concluded that neither shutdown of Indian Point Units 2 or 3 nor imposition of additional remedial actions beyond those already implemented by the licensees was warranted.[806]

The staff also reviewed the Zion PRA and concluded that the risk posed by the Zion plants was small. The dominant contributors to severe accidents at the Zion plants were examined and the staff recommended that: (1) the integrity of the two motor-operated gate valves in the RHR suction line from the RCS be checked each refueling outage, and (2) the diesel-driven containment spray pump be modified so that it is capable of operating without AC power.[806]

Thus, this item was RESOLVED and new requirements were established. DL was to be responsible for managing the implementation of the above recommendations.[806]

ITEM II.B.7: ANALYSIS OF HYDROGEN CONTROL

DESCRIPTION

The accident at TMI-2 on March 29, 1979 resulted in a metal-water reaction which involved hydrogen generation in excess of the amounts specified in 10 CFR 50.44.

As a result, it became apparent to the NRC that additional hydrogen control and mitigation measures would have to be considered for all nuclear power plants.

The purpose of this TMI Action Plan item[48] was to establish the technical basis for the interim hydrogen control measures on small containment structures and to establish the basis for continued operation and licensing of plants, pending long-term resolution of the hydrogen control issue. The long-term resolution of this issue is being accomplished by rulemaking as part of Item II.B.8.

Thus far, a final rule was published on December 2, 1981 requiring inerting of the small MARK I and II (BWR) containments. In addition, based on Commission guidance, interim hydrogen control systems are required as a licensing condition for the intermediate volume ice condenser and MARK III containments. A proposed rule was published on December 23, 1981 (Federal Register 46FR62281) which would require these systems for the intermediate volume containments. Except for pending CP and Manufacturing License (ML) applications, no additional hydrogen control requirements or requirements for hydrogen analyses have been imposed at this time for large dry containments. However, the proposed rule would require that dry containments be analyzed to determine their ability to accommodate the release of large quantities of hydrogen (75% metal-water reaction). Also, hydrogen control requirements have been established as part of the final Near Term CP and ML Rule published on January 15, 1982.

CONCLUSION

Based on the accomplishments above, the basis for continued operation and licensing of plants with respect to the hydrogen control issue has been established. Future work related to finalizing the proposed rule dealing with intermediate volume (Ice Condenser and MARK III) and large dry containments will continue as part of Item II.B.8. Therefore, priority ranking of this issue was not warranted.

ITEM II.B.8: RULEMAKING PROCEEDING ON DEGRADED CORE ACCIDENTS

DESCRIPTION

Historical Background

In the past, safety reviews concentrated on how to prevent a core from being damaged. Consequently, little attention was given to how a severely damaged core could be dealt with after damage occurred. Other subtasks within Task II.B were concerned with the study of the characteristics of degraded and melted cores (research programs) plus some immediate actions to be taken at plants in operation. Item II.B.8 envisioned both a short-term and a long-term rulemaking to establish policy, goals, and requirements to address accidents resulting in core damage greater than the present design basis.

Item II.B.8 included an Advance Notice of Proposed Rulemaking and an Interim Rule. The Advance Notice was issued in December 2, 1980 (45FR65474). The Interim Rule was issued in two parts: the first was issued in effective form in October, 1981 (46FR58484) and the second was issued as a proposed rule on December 23, 1981 (46FR62281).

On January 4, 1982, the staff sent a policy paper, SECY-82-1,[309] to the Commission for action. The paper asked the Commission to reconsider the approach to long-term rulemaking. The events which prompted this request were as follows:

- The Commission had required more protection from severe accidents in some licensing actions (e.g., Sequoyah) than was envisioned in the Action Plan.

- A rule was developed to specify additional requirements for pending construction permit and manufacturing license applications. Again, these reqirements are somewhat more extensive than what was envisioned in the Action Plan.

- New probabilistic risk assessments have indicated lower risk than was previously estimated for large dry PWR containments.

- The safety of current plants has been considerably improved by the modifications guided by NUREG-0737.[98]

- The industry has initiated a program to study the costs and benefits of design features for mitigating severe accidents.

- An extensive research program to study damaged and melted core behavior is underway.

- A safety goal statement, based on probabilistic risk assessment, has been developed.

The substance of SECY-82-1[309] was that the uncertainty associated with long-term rulemaking was and is an inhibiting force on the industry. The paper then recommended that, since new applications are to be standardized anyway, licensing could proceed on these standardized designs using the information presently available. Probabilistic risk assessments and the safety goal would be used to assess plant safety and, if the plant needed safety features beyond the present requirements to meet the safety goal, they could be included. This approach would not need rulemaking specifically directed at severe accident mitigation.

The Commission directed[310] the staff to make several changes in SECY-82-1.[309] The staff then submitted revised papers, SECY-82-1A,[311] on July 16, 1982, and SECY-82-1B, on November 24, 1982. These revised papers incorporated the changes directed by the Commission including ACRS input. The revised papers are still under Commission consideration. The evaluation of this item includes the consideration of Item II.B.7.

Safety Significance

Most of the engineered safety features at nuclear power plants of the current generation are intended to prevent severe core damage. Relatively little attention was given in the past to dealing with a severely damaged or melted core. Once a core is damaged, the containment will still prevent the release of large amounts of radioactive material. However, once the core melts, the containment is likely to fail (although the hazard to the public varies widely, depending on the way in which the containment fails).

The degraded-core accident rulemaking is intended to require means for dealing with a damaged core. This translates into preventing the release of radioactivity and providing means for recovering from the accident. Specific items to be considered included the following: use of filtered, vented containment; hydrogen control measures; core retention devices ("core catchers"); re-examination of design criteria for decay heat removal, and other systems; post-accident recovery plans; criteria for locating highly radioactive systems; effects or accidents at multi-unit sites; and comprehensive review and evaluation of related guides and regulations.

PRIORITY DETERMINATION

The safety significance of this issue is essentially the same as that of the research programs described in the analyses of Items II.B.5(1) and II.B.5(2) above. Examination of the estimated frequency of core damage and/or melt, coupled with estimates of the potential effectiveness of engineering solutions (and their cost) led to a recommendation for high priority for Items II.B.5(1) and II.B.5(2). In the same manner, Item II.B.8 has the potential for a significant (and cost-effective) reduction in public risk.

In addition, it should be noted that some of the plant modifications contemplated are far more expensive to backfit than to forward-fit. Unnecessary delay may well reduce the cost-effectiveness of this item.

CONCLUSION

Based on the above evaluation, this item was given a high priority ranking. Work performed by RES on the hydrogen control aspect of the item resulted in a Hydrogen Control Rule that was approved by the Commission and published in the Federal Register on January 25, 1985.[807] The severe accident portion of the item was addressed in April 1983 by a Policy Statement that set forth the Commission's intentions for rulemakings and other regulatory actions for resolving safety issues related to reactor accidents more severe than design basis accidents (48 FR 16014). Certain severe accident technical issues identified under the discussion of long-term rulemaking will be dealt with for future and existing plants through procedures and ongoing severe accident programs identified in the Policy Statement and described more fully in Chapter IV of NUREG-1070.[809] Thus, with the issuance of the rule on hydrogen control, this item was RESOLVED and new requirements were established.[808]

REFERENCES

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

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.

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.

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

309. SECY-82-1, "Severe Accident Rulemaking and Related Matters," January 4, 1982.

310. Memorandum for W. Dircks from S. Chilk, "Staff Requirements - Briefing on Status and Plan for Severe Accident Rulemaking (SECY-82-1)," January 29, 1982.

311. SECY-82-1A, "Proposed Commission Policy Statement on Severe Accidents and Related Views on Nuclear Reactor Regulation," July 16, 1982.

312. NUREG/CR-0165, "A Value-Impact Assessment of Alternate Containment Concepts," U.S. Nuclear Regulatory Commission, June 1978.

806. Memorandum for W. Dircks from H. Denton, "Closeout of TMI Action Plan, Task II.B.6, 'Risk Reduction for Operating Reactors at Sites With High Population Densities,'" September 25, 1985.

807. Memorandum for W. Dircks from R. Minogue, "Closeout of TMI Action Plan Task II.B.8 'Rulemaking Proceeding on Degraded Core Accidents - Hydrogen Control,'" July 19, 1985.

808. Memorandum for W. Dircks from H. Denton, "Close Out of TMI Action Plan, Task II.B.8," August 12, 1985.

809. NUREG-1070, "NRC Policy on Future Reactor Designs," U.S. Nuclear Regulatory Commission, July 1985.

TASK II.C: RELIABILITY ENGINEERING AND RISK ASSESSMENT

The objective of this task is to develop and implement improved systems-oriented approaches to safety review. The NRC will employ risk-assessment methods to identify particularly high-risk accident sequences at individual plants and determine regulatory initiatives to reduce these high-risk sequences.

ITEM II.C.1: INTERIM RELIABILITY EVALUATION PROGRAM

DESCRIPTION

Historical Background

The Interim Reliability Evaluation Program (IREP) is a planned multiple reliability evaluation program to develop and standardize the reliability methodology involved in performing reliability and safety type studies of this depth. This program was conceived in NUREG-0660[48] as a pilot study and then a scaled-up study of an additional 6 plants.

This issue is concerned with the completion of a shortened 5-plant version of the IREP program. To date, the pilot study has been completed on the Crystal River plant and the results reported in NUREG/CR-2515.[365] Scaled-up analyses have been completed on 4 other plants and the results reported on 2 plants so far: Arkansas Nuclear One-Unit One (NUREG/CR-2787)[366] and Browns Ferry Unit One (NUREG/CR-2802).[367] Remaining is one additional plant, probably a Mark II BWR-type plant. To be included in this analysis would be other common cause initiators, e.g., fires, seismic events, and floods, which were considered in the other IREP analyses.

Possible Solution

The solution used for this issue is to complete the planned analysis and report on the remaining plant.

PRIORITY DETERMINATION

Assumptions

Based on published PRA studies of nuclear power plants, approximately one-third have predicted core-melt frequencies exceeding 10^{-4} event/year. It could be assumed for purposes of this evaluation that these plants exceeding 10^{-4} event/year have an average core-melt frequency of 3×10^{-4} event/yr which may be reduced to 10^{-4} event/year.

Frequency Estimate

As stated in the assumptions above, we will assume that there is a one-in-three chance that the reactor which is to be analyzed will have a predicted core-melt frequency of 3×10^{-4} event/year and that this frequency will be reduced to 10^{-4} event/yr, a frequency reduction of 2×10^{-4} event/yr or a probable frequency reduction of 6.7×10^{-5} core-melt/yr.

Consequence Estimate

Consequences relating to this item are expressed in man-rem. The total whole body man-rem dose is obtained using the CRAC Code[64] for the release fractions and categories of a BWR as given in WASH-1400.[16] The calculations assume an average population density of 340 persons per square mile (which is the average for U.S. domestic sites) from an exclusion area of one-half mile about the reactor out to a 50-mile radius about the reactor. A typical midwest plain meteorology is also assumed. It is further assumed that the reduction in public dose is in proportion to the reduction in accident frequency.

Assuming an average public risk exposure of 6.8×10^{6} man-rem/core-melt and an average remaining life of 27 years for BWRs, the reduction in core-melt frequency of 6.7×10^{-5} event/RY results in a reduction in public risk of 455 man-rem/RY, and a total public risk reduction of 12,150 man-rem for all affected plants.

Cost Estimate

Industry Cost: The contract costs of performing the analyses involved with the prior IREP assessed plants have averaged \$900,000/plant. Since we cannot predict what may be identified by the analysis as candidate modifications to reduce risk, the plant change cost cannot be estimated. However, based upon a risk reduction of 12,000 man-rem, it would be cost-effective for the plant owners to spend up to \$12M for this reduction in risk.

NRC Cost: NRC costs to review the analysis and prepare findings is estimated to be \$200,000 plus 0.7 staff-year or \$270,000. It is further assumed that, as in the case with the initial IREP plant analysis, the analysis cost will be borne by NRC. This results in a total NRC cost of \$1.2M.

The total cost associated with the solution to this issue is \$(12 + 1.2)M or \$13.2M.

Value/Impact Assessment

Based on a public risk reduction of 12,000 man-rem, the value/impact score is given by:

$$S = \frac{12{,}000 \text{ man-rem}}{\$13.2\text{M}}$$

$$= 910 \text{ man-rem/\$M}$$

Other Considerations

The findings from this analysis may help to identify generic safety issues for other reactors in the same class. In addition, an additional purpose for this study is to demonstrate the suitability of newly developed methodology for the inclusion of external initiating events into PRA calculations. However, no credit for this benefit has been considered or factored into the value/impact assessment for this item.

CONCLUSION

Based on the value/impact score, this issue would have received a medium priority ranking. However, given the potential public risk reduction, it was deemed to have a high priority. Work completed by the staff resulted in the publication of the following reports for the two remaining plants: NUREG/CR-3085[810] and NUREG/CR-3511[811] for Millstone Unit 1 and Calvert Cliffs Unit 1, respectively. A primary output of the IREP was NUREG/CR-2728[812] which is a guide that documents methods, codes, and data used in the IREP. This guide is intended to provide guidance for PRAs performed subsequent to IREP. Thus, this item was RESOLVED and no new requirements were established.[813]

ITEM II.C.2: CONTINUATION OF INTERIM RELIABILITY EVALUATION PROGRAM

DESCRIPTION

Historical Background

IREP is a planned multiplant reliability evaluation to develop and standardize the reliability methodology involved in performing reliability and safety-type studies of this depth. It was conceived in NUREG-0660[48] that a National Reliability Evaluation Program (NREP) study, performed by the plant owners, should follow the IREP effort.

This issue is concerned with the continuation of the IREP program to cover all the remaining operating reactors which were not covered in the initial IREP studies either performed by NRC or performed by plant owners. Also, consideration is being given to include plants under design or construction.

Possible Solutions

Possible solutions to this issue may range from the NRC sponsoring an analysis of all plants, having the individual utilities perform an analysis on all or some plants, or reducing the effort to a limited type study. The plan selected for this analysis consists of three parts: (1) performance of an NREP by the plant owners on 4 plants currently without a risk/reliability type analysis, (2) a careful review by the NRC of 7 other plants that currently have an existing PRA, and (3) an appraisal of the interim results of these reviews a year after implementation to consider the advisability of future extension of the NREP program to other plants. These 11 plants would be the same ones chosen for the first group of SEP Phase III plants.

PRIORITY DETERMINATION

Assumptions

At present there are 14 published PRA studies, and the core-melt frequencies are predicted to be higher than 10^{-4}/RY in about one-third of these studies. Thus, it could be assumed for purposes of value/impact analysis that, of the 11 plants to be studied, about 4 might have some hardware or procedural fixes implemented to reduce the likelihood of the most dominant accident sequences with respect to core-melt. In addition, there is a potential that these analyses will result in generic resolutions of identified safety issues which could reduce risk at other plants without the expense of plant-specific PRAs being performed at these plants; but this assumption remains to be proven. Calculations are partly based upon work performed by PNL and reported in NUREG/CR-2800.[64]

Frequency Estimate

It is not unrealistic to postulate that 4 of the 11 reactors have an average core-melt frequency of 3×10^{-4}/RY and that changes are possible to reduce the core-melt frequency to 10^{-4}/RY. Therefore, a reduction in core-melt frequency of 2×10^{-4}/RY is postulated for these 4 plants.

Consequence Estimate

Assuming an average public exposure of 2.5×10^6 man-rem and 6.8×10^6 man-rem following a core-melt at a PWR and a BWR, respectively, the reduction in core-melt frequency results in a reduction in public risk of about 42,700 man-rem for the remaining life of the 3 PWRs and 36,700 man-rem for the remaining life of the BWR. This results in a total reduction in public risk of approximately 79,000 man-rem.

Cost Estimate

Industry Cost: Based on previous experience, the industry cost for each plant is expected to be between \$1.5M to \$2M to perform the NREP analysis (presently limited to analysis of core-melt from internal accident initiators), including a state-of-the-art systems interaction study of appropriate scope and depth. For purposes of performing this value/impact study, we will use the upper bound utility cost and assume that the total utility costs are \$2M/reactor and, of that amount, \$500,000 is the additional cost of performing the systems interaction in conjunction with the NREP. For the 4 plants to be analyzed, the total industry costs for the NREP analysis would thus be \$6M. For an effective cost-benefit ratio (based on a 79,000 man-rem risk reduction), the utility backfit cost could be as high as \$73M.

NRC Cost: The NRC costs are estimated to be \$200,000 and 0.7 man-year/reactor. Thus, the total NRC cost for the 11 reactors is estimated to be \$3.8M.

The total cost associated with the solution to this issue is \$(6 + 73 + 3.8)M or \$82.8M.

Value/Impact Assessment

Based on a total risk reduction for all reactors of 79,000 man-rem, the value/impact score is given by:

$$S = \frac{79,000 \text{ man-rem}}{\$82.8\text{M}}$$

$$= 950 \text{ man-rem/\$M}$$

Other Considerations

The value/impact score is strongly influenced by the uncertainty of the cost figures for the utility. Considerable risk reduction has been achieved by procedural changes which can be developed and implemented at much less cost than equipment changes. Therefore, the cost of utility implementation may be considerably less than the cost figure used in this assessment.

CONCLUSION

Although the value/impact score of this issue would only warrant a medium priority ranking, the large potential risk reduction (brought about by the reduction in core-melt frequencies for those plants that are above 10^{-4}/RY indicated that a high priority ranking should be assigned.

Work completed by the staff on this item was closely related to the accomplishments under Item IV.E.5. Whereas Item II.C.2 called for the initiation of IREP studies (i.e., plant-specific PRAs) on all remaining operating reactors, Item IV.E.5 called for the development of a plan for the systematic assessment of the safety of all operating reactors. The Integrated Safety Assessment Program (ISAP), presented in SECY-84-133[814] and SECY-85-160,[815] provided for a comprehensive review of selected operating reactors to address all pertinent safety issues and to provide an integrated cost-effective implementation plan for making needed changes. Under ISAP, each plant would be subject to an integrated assessment of safety topics, a probabilistic safety assessment, and an evaluation of operating experience.

NRC guidance, as described in the Severe Accident Policy Statement (see Item II.B.8), states that OLs will be expected to perform plant-specific PRAs in order to discover instances of particular vulnerability to a core-melt or poor containment performance, given a core-melt. Thus, this item was RESOLVED and no new requirements were established.[816]

ITEM II.C.3: SYSTEMS INTERACTION

DESCRIPTION

The design of a nuclear power plant is accomplished by groups of engineers and scientists organized into engineering and scientific disciplines such as civil, electrical, mechanical, structural, chemical, hydraulic, nuclear, geological, seismological, and meteorological. The reviews performed by the designers include interdisciplinary reviews to assure the functional compatibility of the plant structures, systems, and components. Safety reviews and accident analyses provide further assurance that system functional requirements will be met. These reviews include failure mode analyses to assure that the single failure criterion is met.

The design and analyses by the plant designers. and the subsequent review and evaluation by the NRC staff, take into consideration some interdisciplinary areas of concern and account for systems interaction to a large extent. Furthermore, many of our regulatory criteria are aimed at controlling the risks from systems interactions. Examples include the single failure criterion and separation criteria.

Nevertheless, based upon actual operating experience, there is some question regarding the interaction of various plant systems both as to the supporting roles such systems play and the effect one system can have on other systems, particularly with regard to whether actions or consequences could adversely affect the presumed redundancy and independence of safety systems. The objective of a systems interaction analysis is to provide assurance that the independent functioning of safety systems is not jeopardized by preconditions that cause faults to be dependent.

Concern over systems interactions was first documented explicitly by the ACRS in November 1974 when they requested that the NRC given "...attention to the evaluation of ... potentially undesirable interactions between systems ..." from a multi-disciplinary point of view. In December 1977, NUREG-0371[2] was revised to include Item A-17, "Systems Interactions in Nuclear Power Plants." In May 1980, NUREG-0660[48] provided for broadening the staff efforts in Item II.C.3. Efforts for the resolution of Item II.C.3 are now included in activities for the resolution of USI A-17.

CONCLUSION

This issue is not considered a separate generic issue since it is covered in USI A-17.

ITEM II.C.4: RELIABILITY ENGINEERING

DESCRIPTION

Historical Background

There is currently no requirement for the plant owners to develop and implement a reliability assurance program. Such programs, typically, determine system availabilities, identify high component failure rates, determine basic causes for component failures, identify possible corrective actions, and perform other similar activities in what is generally called reliability engineering. In the absence of a requirement, it is difficult to determine the nature and extent that is now being exercised by the plant owners to implement a reliability assurance program. This issue was identified in the TMI Action Plan[48] as the final item of Task II.C.

Possible Solutions

A possible solution is to develop a regulatory guide which would define the elements and functions necessary for an applicant to plan and establish an acceptable reliabililty program. Applicants would further be required to implement the operation of a reliability program as a part of the requirements to obtain a construction permit or operating license. The functioning of the reliability program would be inspected as a part of the ongoing inspection program.

PRIORITY DETERMINATION

Assumptions

Issues of this nature are difficult to quantify since the results are highly speculative depending upon such hard to quantify variables as management acceptance and backing. The approach used to estimate the effectiveness of this issue is to determine what might be a reasonable objective and evaluate the contribution to risk reduction which can be achieved and at what costs.

The defined objective for this evaluation is to maintain the reduction in core-melt frequency which was achieved by the NREP program. From previous probabilistic risk assessments and IREP analyses published to date, about one third of the plants had forecast accident frequencies which exceeded 10^{-4}/RY. It is further assumed that, without a dedicated effort, the accident frequency for these plants would rise to 2×10^{-4}/RY at the end of the plant life. At a constant rate of increase in accident frequency over the balance of plant life, the average increase would be 5×10^{-5} event/RY. Release fractions were based on the Oconee and Grand Gulf plants. Quantifications used in this issue are based partly upon work done by PNL and reported in NUREG/CR-2800.[64]

Frequency/Consequence Estimate

The reduction in core-melt frequency for 33% of the reactors is 5×10^{-5} event/RY as previously described. The core-melt frequency reduction results in a risk reduction of 128.5 man-rem/RY for PWRs and 338 man-rem/RY for BWRs. Based upon 33% of the PWRs and BWRs, 31 PWRs with an average estimated remaining life of 28.5 years and 16 BWRs with an average remaining life of 27 years, the risk reduction would be 120,900 man-rem for PWRs and 146,200 man-rem for BWRs. The total risk reduction would be 267,100 man-rem.

Cost Estimate

Industry Cost: The plant user costs, based on the estimate in NUREG-0660,[48] are 10 man-years/plant to establish a program and 1 man-year/RY sustaining costs for the plant life. The total costs are \$143M for implementation and \$400M for operation. Thus, the total industry costs are \$543M.

NRC Cost: NRC costs are estimated to be 3 man-years for implementation for a cost of \$300,000. The cost for operation is estimated to be 2 man-weeks/RY or a cost of \$15.4M for the remaining life of all the reactors. The total NRC cost is thus estimated as \$15.7M.

The total cost associated with the solution to this issue is \$(543 + 15.7)M or \$558.7M.

Value/Impact Assessment

Based on a total risk reduction estimate of 267,100 man-rem, the value/impact score is given by:

$$S = \frac{267{,}100 \text{ man-rem}}{\$558.7\text{M}}$$

$$= 478 \text{ man-rem/\$M}$$

Other Considerations

One of the factors which drives the utility costs up in the calculations of this issue is the annual costs associated with the maintenance of the program. However, given the cost of replacement power at \$300,000/day, one day of increased productivity from increased plant reliability would cover three years of forecast reliability program operating costs. A reliability program should have economic incentives to the plant owners in addition to the safety incentives.

The risk reduction for the issue was calculated only for those plants which were predicted to have a core-melt frequency which exceeds 10^{-4}/RY. An additional reduction in risk would also be realized by maintaining the core-melt frequency at the calculated value on those plants which had a core-melt frequency less than 10^{-4}/RY.

CONCLUSION

The priority ranking of this issue based solely on the value/impact score would be medium. However, based upon the core-melt frequency change per reactor year, this issue is assigned a HIGH priority ranking. Additionally, as previously described, there is a large cost incentive to the utility to be realized from increased availability.

REFERENCES

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

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.

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.

365. NUREG/CR-2515, "Crystal River 3 Safety Study," U.S. Nuclear Regulatory Commission, December 1981.

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.

367. NUREG/CR-2802, "Interim Reliability Evaluation Program: Analysis of the Browns Ferry Unit 1 Nuclear Plant," U.S. Nuclear Regulatory Commission, July 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.

813. Memorandum for W. Dircks from R. Minogue, "Closeout of TMI Action Plan Task II.C.1, 'Interim Reliability Evaluation Program,'" July 9, 1985.

814. SECY-84-133, "Integrated Safety Assessment Program (ISAP)," March 23, 1984.

815. SECY-85-160, "Integrated Safety Assessment Program - Implementation Plan," May 6, 1985.

816. Memorandum for W. Dircks from H. Denton, "Close-out of Generic Issues II.C.2 'Continuation of IREP,' and IV.E.5 'Assess Currently Operating Reactors,'" September 25, 1985.

TASK II.E.2: EMERGENCY CORE COOLING SYSTEM

The objectives of this task are as follows: (1) to decrease reliance on the emergency core cooling system (ECCS) for other than loss-of-coolant accidents, (2) to ensure that the ECCS design-basis reliability and performance are consistent with operational experience, (3) to reach better technical understanding of ECCS performance, and (4) to ensure that the uncertainties associated with the prediction of ECCS performance are properly treated in small-break evaluations.

ITEM II.E.2.1: RELIANCE ON ECCS

DESCRIPTION

Historical Background

This TMI Action Plan[48] item calls only for the collection of ECCS operating experience. Risk reduction would require that conclusions and recommendations be made and acted upon. Since the stated purpose of the task is to decrease the reliance on ECCS for other than LOCAs, it was assumed that this task would ultimately lead to the implementation of some hardware modifications.

Safety Significance

The ECCS of PWRs and BWRs are currently being actuated for other than LOCAs. Reliance on the ECCS for other than LOCAs should be evaluated to ensure that: (1) the ECCS design basis reliability and performance are consistent with operational experience, and (2) to reach a better technical understanding of ECCS performance.

Possible Solution

In accordance with Item II.K.3(17),[98] licensees were requested to submit a report detailing dates and length of all ECCS outages for the last 5 years of operation, including causes of the outages. This report would provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

The requested report was to contain: (1) outage dates and duration of outages; (2) cause of the outage; (3) ECCS systems or components involved in the outage; and (4) corrective action taken. Test and maintenance outages were to be included in the above listings covering the last 5 years of operation. The licensees were requested to propose changes to improve the availability of ECCS equipment, if needed.

Thirty out of sixty-five Technical Evaluation Reports (TERs) are expected from Franklin by September 30, 1982. Nine have been received so far. RRAB will issue SERs to DL for these thirty plants by November 15, 1982 and the task will be closed out by DL by December 31, 1982. By December 31, 1982, Franklin will issue the remaining 25 TERs and SERs will be issued for these plants by RRAB by February 15, 1983. The final 35 actions will be closed out by DL by March 31, 1983.

CONCLUSION

This issue is covered under Item II.K.3(17) which is being implemented as part of NUREG-0737.[98]

ITEM II.E.2.2: RESEARCH ON SMALL BREAK LOCAs AND ANOMALOUS TRANSIENTS

DESCRIPTION

Historical Background

This TMI Action Plan[48] item was intended to focus research on small breaks and transients. It includes experimental research in the LOFT Semiscale, BWR FIST, and B&W Integral Systems Test facilities, systems engineering, and materials effects programs, as well as analytical methods development and assessments in the code development program. Most of the experimental work for small-break (SB) LOCAs was completed in FY 1982, with data analysis to be conducted in FY 1983. The methodology used in this analysis considers only future costs. Since October 1982, the LOFT project has been supported by an international consortium, of which NRC is a member.

Safety Significance

The primary goal of the small-break and transient research is to improve operator performance during off-normal events. The research on analytical methods development and assessment is directed toward improving current computer codes, development and application of advanced computer codes for SBLOCA and other accident analysis, and development of a fast, easy to use, engineering analyzer capability.

Possible Solution

Part of the program was to examine SBLOCAs and anomalous transients. Specifically, the ability of typical process instruments to provide accurate and sufficient information to operating personnel. Advanced control room and diagnostic instrumentation was used in LOFT as part of the augmented operator capabilities program to assess operator needs to mitigate the consequences of LOCA and transient sequences.

PRIORITY DETERMINATION

Assumptions

The analysis of this issue was performed by PNL[64]. For purposes of this analysis, only reduction in operator error during LOCA and transient sequences is assumed for issue resolution. It is assumed that small break LOCAs or transients leading to a LOCA, typically via a stuck-open pressure relief valve, represent the initiating events applicable to this issue. Using Oconee 3 as a representative PWR, these initiators are an S_3 LOCA and T_1, T_2, or T_3 transient coupled with relief valve closure failure (Q). This applies primarily to PWRs; however, the same approach was used in the BWR analysis.

For PWRs, it was assumed that operator errors involved: (1) failure to align suction of high pressure recirculation system to the suction of the low pressure recirculation system, and (2) failure of operator to open both containment sump suction valves in the low pressure containment spray recirculation system at the start of recirculation. For BWRs it was assumed that the operator failed to manually initiate the ADS system. Operator error in such sequences are assumed to be reduced by one-third as a result of a combination of operator training and improved instrumentation.

Frequency/Consequence Estimate

Based on the above assumptions and using the dominant accident sequences, the reductions in core-melt frequencies were calculated to be 5.2×10^{-6}/RY for PWRs and 1.8×10^{-7}/RY for BWRs. The reductions in public risk per plant were calculated to be 15 man-rem/RY for PWRs and 0.5 man-rem/RY for BWRs. Assuming 90 PWR plants with an average remaining life of 28.8 years and 44 BWR plants with an average remaining life of 27.4 years, the total public risk reduction is 41,000 man-rem for all forward-fit and backfit plants.

Cost Estimate

Industry Cost: The industry cost is estimated to be $0.5M per facility to upgrade operator training and install upgraded equipment. It is assumed that equipment installation is primarily in the control room, with no increase in radiation exposure, and that only backfit plants are involved. Therefore, assuming 47 PWRs and 24 BWRs, the industry cost is estimated to be $36M. This cost is applied to backfit plants only since the changes resulting from this program will presumably be incorporated into the initial design and licensing of the forward-fit plants.

NRC Cost: This item is an ongoing program; therefore, sunk costs have already been taken in FYs 1980, 1981, and 1982. It is estimated that 20 percent of the FY 1983 LOFT budget is earmarked for the SBLOCA program. This represents approximately $3.1M . In addition, it is assumed that $0.2M will be required to establish new criteria for reactor instrumentation and operator training. NRC annual review is estimated to require an additional 1 man-day/RY ($1.7M). The NRC cost is, therefore, estimated to be $5M.

The total cost associated with the solution to this issue is $(36 + 5)M or $41M.

Value/Impact Assessment

Based on a public risk reduction of 41,000 man-rem, the value/impact score is given by:

$$S = \frac{41{,}000 \text{ man-rem}}{\$41\text{M}}$$

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

CONCLUSION

Based on a potential public risk reduction of 41,000 man-rem, a value/impact score of 1,000 man-rem/$M, and a reduction in core-melt frequency of less than 10^{-5}/RY, this issue was ranked medium priority. The test program called for by this item was completed by the staff and showed that emergency core cooling systems will provide adequate core cooling for SBLOCAs and anomalous transients consistent with the single failure criteria of 10 CFR 50, Appendix K. Ongoing thermal hydraulic research is aimed at defining the degree of uncertainty in the ability of present analytical models to simulate those transients on full-scale LWRs and not at proving capability. Thus, this item was RESOLVED and no new requirements were established.[817]

ITEM II.E.2.3: UNCERTAINTIES IN PERFORMANCE PREDICTIONS

DESCRIPTION

Historical Background

TMI Action Plan[48] item is described as follows:

> "Small-break LOCA analyses performed by the LWR vendors to develop operator guidelines have shown that large uncertainties may exist in system thermal-hydraulic response due to modeling assumptions or inaccuracies. It is necessary to establish that these assumptions or inaccuracies are properly accounted for in determining the acceptability of ECCS performance pursuant to Appendix K of 10 CFR 50."

The reason behind this concern was that historically the SBLOCA analyses were never reviewed by the NRC staff in the depth and detail with which the large-break analyses were reviewed. One of the obvious lessons of the TMI-2 accident was that SBLOCAs are much more likely to occur and, therefore, a highly detailed re-review of the small-break analyses might be appropriate.

Safety Significance

SBLOCAs do not automatically result in rapid depressurization of the primary system. The more complicated blowdown makes it more difficult to predict ECC injection flow rates, water level, and many other parameters as a function of time. Moreover, there are many more possible locations for the break. In addition, the possibility of unexpected thermal-hydraulic phenomena cannot be ruled out. Since the SBLOCA analyses must conservatively bound the plant's response to all possible small breaks, all of these effects should be understood as well as possible.

Possible Solution

The proposed solution is straightforward. NUREG-0660[48] describes the proposed program as follows:

> "NRR will issue instructions to holders of approved ECCS evaluation models to evaluate the uncertainty of small-break ECCS performance

calculations. NRR will evaluate these uncertainties. If changes are needed in the present analysis methods to properly account for these uncertainties recommendations will be made to the Commission to adopt such changes."

Ultimately, the adoption of these changes would result in changes to the analyses upon which plant technical specifications are based. This could result in some restrictions on power level under certain circumstances.

PRIORITY DETERMINATION

Frequency Estimate

According to WASH-1400[16] estimates, small breaks (2 in. to 6 in. diameter) are expected to occur at a rate of 3×10^{-4} event/RY. Very small breaks (0.5 in. to 2 in. diameter) are estimated to occur at a rate of 10^{-3} event/RY. Should such an event occur, we estimate (based purely on judgment) that there may be a 10% chance of the actual peak cladding temperatures exceeding the temperatures predicted by the Appendix K calculation due to the modeling uncertainties mentioned above.

However, in addition to the modeling conservatism, the Appendix K calculations assume the worst case single failure. Moreover, the small break analysis is very seldom limiting; usually the calculated small break peak cladding temperatures are about 400°F below the 2200°F Appendix K limit. Finally, the plant does not normally operate with the LOCA parameters (F_Q, MAPLHGR, etc.) at their limits.

Because the specific worst-case single failure varies for different plants, it is not practical to use fault trees to calculate the probability of such a failure. However, some perspective can be gained by examining the following estimated failure rates from Appendix II of WASH-1400:[16]

PWR HPSI	1.2×10^{-2}/demand
PWR Emergency Power	10^{-5}/demand
BWR HPCI	9.8×10^{-2}/demand
BWR Emergency Power	10^{-6}/demand

We will estimate the probability of a system failure severe enough to approximate the Appendix K single failure assumptions to be, at most, 10^{-1}/demand. Given a small LOCA, a modeling uncertainty, and something approximating the worst-case single failure, the actual peak cladding temperature will be greater than that calculated by the analyses. However, there is still considerable margin to significant core damage because:

(1) The small-break analysis is rarely limiting. Usually there is about a 400°F margin between the calculated small-break peak cladding temperature and the 2200°F limit.

(2) Most plants operate well within their LOCA limits (i.e., are not "LOCA-limited").

(3) To get severe damage, a significant amount of cladding must achieve a temperature significantly higher than 2200°F. The case of the hottest point of the core barely exceeding the temperature limit does not automatically imply severe damage.

We will sum up these three considerations by assuming that there is, at most, a 5% chance of significant core damage given a small LOCA, a model problem, and a near-worst-case single failure. Putting all this together, the frequency of events with significant core damage is estimated to be, at most, about 7×10^{-7}/RY.

Consequence Estimate

If cladding temperatures rise significantly above 2200°F in a large portion of the core, the likely result is a bed of debris. We will assume that there is a 10% chance of a core-melt and a 90% chance of widespread cladding failure but no fuel melting. Neither of these fits readily into the WASH-1400[16] Release Categories. We will approximate the core-melt case with 5×10^6 man-rem (which is greater than or approximately equal to the consequences of PWR-1 through PWR-7 and BWR-1 through BWR-4), and the non-core-melt case by 120 man-rem (which bounds PWR-9 and BWR-5).

Cost Estimate

It was estimated[48] that 15 staff-years and $1M of computer time would be required for the industry to perform the studies. We will add to this 3 staff-months per operating plant to implement procedural and technical specification changes. Since there are 70 plants operating, the estimated total direct industry cost is $4.25M (The 57 plants under construction would not require implementation costs, since the new analyses would displace analyses which would have been required in any case.)

In addition to this direct cost, there is an indirect cost to the industry due to the effect of further restricting operating parameters. If we use our earlier assumptions that there is a 10% chance of finding a non-conservatism and a 5% chance of being SBLOCA-limited, and assume further that at least a 1% power reduction results under such circumstances, the indirect costs average out to at least $5,500/RY.

We estimate that 15 staff-years and $100,000 would be necessary for the NRC staff to review these studies. In addition, the 70 backfit plants would require one staff-month each. (Again, the 57 plants under construction would not need a significant amount of extra review effort, since the new reviews would displace the reviews of other analyses which would have been submitted.) Thus, NRC costs are estimated to be about $1.2M.

Currently, there are 43 operating PWRs with a cumulative experience of 350 RY and 27 BWRs with a cumulative experience of 260 RY. If we add to these the 36 PWRs and 21 BWRs under construction and assume a plant lifetime of 40 years, there are 4,470 RY in the future. Therefore, the total cost associated with this issue is $30.05M.

Value/Impact Assessment

Based on a total risk reduction of 1,565 man-rem, the value/impact score is given by:

$$S < \frac{1,565 \text{ man-rem}}{\$30.05M}$$

$$< 52 \text{ man-rem/\$M}$$

CONCLUSION

Based on the safety importance and value/impact score above, this issue should be ranked low priority. In addition, RSB has noted that much of the technical concern of this issue is automatically being investigated by TMI Action Plan Item II.K.3(30), "Revised SBLOCA model to comply with 10 CFR 50.46, Appendix K," currently in progress.[98] In order to prevent duplication of effort, and because the work on Item II.K.3(30) is also producing progress on this issue, it is recommended that this issue be given a LOW priority.

REFERENCES

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

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

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

817. Memorandum for W. Dircks from R. Minogue, "Closeout of TMI Action Plan Task II.E.2.2, Research on Small Break LOCAs and Anomalous Transients," July 25, 1985.

TASK III.A: EMERGENCY PREPAREDNESS AND RADIATION EFFECTS

TASK III.A.1: IMPROVE LICENSEE EMERGENCY PREPAREDNESS - SHORT TERM

The objectives of this task are to improve and upgrade licensee emergency preparedness by requiring improvements in facilities, plans, procedures, offsite support, technical assistance, equipment, and supplies required to adequately respond to and manage an accident.

ITEM III.A.1.3: MAINTAIN SUPPLIES OF THYROID BLOCKING AGENT

Both parts of this item have been combined and evaluated together.

DESCRIPTION

Historical Background

This TMI Action Plan item[48] addressed the issue of providing potassium iodide (KI) as a thyroid blcking agent for, first, nuclear power plant onsite personnel and offsite emergency response personnel, and second, the general population near nuclear power plants.

NUREG-0654[224] required the licensees to have adequate supplies of KI available for onsite personnel and for offsite emergency response support personnel, including offsite agencies. The item also called for an evaluation by the Department of Health and Human Services (HHS) and the Environmental Protection Agency (EPA) regarding use of KI by the general public.

In accordance with SECY-82-396A,[369] RES is expected to complete by January 1983 a technical paper which evaluates the cost benefit of the use of KI by the general public. These results will be sent to the other Federal agencies involved with the final decision.

Safety Significance

It is possible that a nuclear power reactor accident could release radionuclides, including isotopes of radioiodine, into the environment. The radioactive iodine if taken up by the thyroid gland could induce nodules of cancer in the thyroid.[64]

Possible Solution

If stockpiles of KI are made available for public use, the KI could help prevent radiation injury to the thyroid gland by saturating the gland with non-radioactive iodine.[64] This would block the thyroid from taking up the radioactive iodine.

CONCLUSION

The licensees are already required to maintain supplies of the thyroid blocking agent (KI) as a protective measure for emergency workers and other individuals onsite during an emergency.[48,224] Therefore, Item III.A.1.3(1) has been resolved.

Work completed by the staff on the subject of stockpiling KI for public use, resulted in a cost/benefit study which was published in NUREG/CR-1433.[831] HHS completed its recommendations on the methods for administration of KI to the general public (130 milligrams/day at projected thyroid doses of 25 rem or greater) and published them in the Federal Register in 1982 (47 FR 28158). NUREG/CR-1433[831] showed that the use of KI by the general public has a very low cost/benefit ratio. FEMA, through a special subcommittee of the Federal Radiological Preparedness Coordinating Committee (FRPCC), developed a draft Federal policy statement in July 1982 on the use of KI for thyroidal blocking by the general public. This draft policy statement left the decision on distribution and use of KI for thyroidal blocking by the general public to the state and local authorities on a site-specific basis. The HHS guidance on KI use was addressed in the statement as well as many of the problems and difficulties in distribution and administration of the drug (e.g., timeliness, interference with other protective actions, and limited protection). The NRC staff did not agree with the draft Federal policy statement because it believed that the statement should recommend that KI not be distributed for use by the general public. A new cost/benefit study was prepared using an uncertainty analysis of the information in NUREG/CR-1433[831] and showed that KI offered an extremely small benefit in relation to its cost over the uncertainty range.

The new cost/benefit study and prepared changes to the draft Federal policy statement were reviewed by the ACRS and forwarded to the Commission for consideration on August 31, 1983 (SECY-83-362).[832] While the Commission was considering the staff position, FEMA decided to revise the draft Federal policy statement because of the lack of concurrence by NRC and several other member agencies of the FRPCC. The Commission decided to review this new policy statement before responding to FEMA.

The new draft Federal policy statement was completed by the FRPCC on March 26, 1985 and was sent to the Commission for review on May 13, 1985 (SECY-85-167).[833] This new policy statement recommended against a nationwide requirement for the distribution or stockpiling of KI for use by the general public and left the final decision for its use to state and local authorities on a site-specific basis. On June 11, 1985, the Commission concurred with the new policy statement. On June 24, 1985, the staff informed FEMA that the Commission concurred with the new policy statement. FEMA published the policy statement in the Federal Register on July 24, 1985 (50 FR 30258).

With the publication of the Federal policy statement on the distribution and stockpiling of KI for use in the event of a nuclear power reactor accident, this item was RESOLVED and no new requirements were established.[818]

ITEM III.A.1.3(1): WORKERS

This item was evaluated in Item III.A.1.3 above and was determined to be RESOLVED. No new requirements were established.[818]

ITEM III.A.1.3(2): PUBLIC

This item was evaluated in Item III.A.1.3 above and was determined to be RESOLVED. No new requirements were established.[818]

REFERENCES

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 Develpoment," U.S. Nuclear Regulatory Commmission, February 1983.

224. NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," U.S. Nuclear Regulatory Commission, February 1980.

369. SECY-82-396A, "Withdrawal of SECY-82-396 (Federal Policy Statement on Use of Potassium Iodide)," October 15, 1982.

379. Memorandum for H. Denton from R. DeYoung, "Draft Report on the Prioritization of Non-NRR TMI Action Plan Items," January 24, 1983.

818. Memorandum for W. Dircks from J. Taylor, "TMI Action Plan - Completed Item," August 15, 1985.

831. NUREG/CR-1433, "Examination of the Use of Potassium Iodide (KI) as an Emergency Protective Measure for Nuclear Reactor Accidents," U.S. Nuclear Regulatory Commission, October 1980.

832. SECY-83-362, "Emergency Planning - Predistribution/Stockpiling of Potassium Iodide for the General Public," August 30, 1983.

833. SECY-85-167, "Federal Policy Statement on the Distribution and Use of Potassium Iodide," May 13, 1985.

TASK III.D.2: PUBLIC RADIATION PROTECTION IMPROVEMENT

The objective of this task is to improve public radiation protection in the event of a nuclear power plant accident by improving: (1) radioactive effluent monitoring; (2) the dose analysis for accidental releases of radioiodine, tritium, and carbon-14; (3) the control of radioactivity released into the liquid pathway; (4) the measurement of offsite radiation doses; and (5) the ability to rapidly determine offsite doses from radioactivity release by meteorological and hydrological measurements so that population-protection decisions can be made appropriately.

ITEM III.D.2.1: RADIOLOGICAL MONITORING OF EFFLUENTS

The three parts of this item have been combined and evaluated together.

DESCRIPTION

Historical Background

This TMI Action Plan[48] item required development and implementation of acceptance criteria for monitors used to evaluate effluent releases under accident and postaccident conditions. Criteria would be developed for pathways to be monitored (stack, plant vent, steam dump vents) as well as for monitoring instrumentation. To meet the new criteria, licensees would have to develop, procure, and install monitoring systems which are currently beyond the state-of-the-art. This is seen to encompass the requirements in NUREG-0578,[57] Recommendation 2.1.8-b, and Appendix 2 to NUREG-0654.[224]

The envisioned monitoring system would provide automatic on-line analysis of airborne effluents including isotopic analyses of particulate, radioiodine and gas samples. To prevent saturation of detectors, an automatic sample cartridge changeout feature would be included. The system would include microprocessor control and real-time readouts and would be located in a low postaccident background area. The sampling system would be designed to provide a representative sample under anticipated accident release conditions.

A PWR steam-dump sampling and monitoring system would be provided for PWR safety relief and vent valves. Such a system might consist of a noble gas monitor and a radioiodine sampling and monitoring system. The features of such a system would be similar to the above described airborne effluent monitor with two notable differences: (1) the system would be required to function in a very high humidity (steam-air mixture) environment, and (2) operation would only be required during actual steam venting. Because such venting is usually of a short-term or intermittent duration, the monitoring system activation could be keyed to the opening of the vents.

Liquid effluents are not envisioned as posing a major release pathway because licensees typically have installed, or are installing, adequate storage capacity to prevent discharges. Consequently, present liquid effluent monitoring systems are considered adequate.

Safety Significance

This issue has no impact on core-melt and very little impact on public risk.

Possible Solution

For the purpose of this analysis, it will be assumed that improved radiological monitoring of airborne effluent would result in a reduction of public risk.

PRIORITY DETERMINATION

Frequency/Consequence Estimate

The magnitude of public risk reduction attributable to improved radiological monitoring of airborne effluents is not certain, but it was estimated by PNL[64] to range from zero to 1%, based on the following logic.

Present radiological monitoring requirements, as contained in NUREG-0737,[98] require real-time noble gas monitoring with sampling and laboratory analysis capabilities for radioiodines and particulates. Design basis conditions defined in NUREG-0737[98] (100 µCi/cc radioiodines and particulates, 30-minute sample time) indicate that sample collection devices would pose special handling and analysis problems due to very high radioactivity buildup. Consequently, licensees have typically provided alternate sample collection and analysis procedures. Execution of those procedures is estimated to require between 2 to 3 hours. During this time, radioiodine and particulate releases would be estimated based on computer-modeled interpretation of noble gas monitor readings, or on previous postaccident containment atmosphere analysis results, if such results were available. Public protective action recommendations would be made based on modeled estimates rather than actual effluent data. It is assumed that these recommendations would err on the conservative side (e.g., evacuate when not really required) due to the conservatism built into the modeled source terms for radioiodine and particulate releases.

Requiring licensees to have more sophisticated airborne effluent monitors would reduce the time required for obtaining actual radioiodine and particulate release data to 15 minutes, and essentially eliminate reliance on conservative theoretical release models extrapolated from noble gas monitor readings. As projected by this safety issue resolution, real-time isotopic monitoring would save nearly two hours in arriving at realistic protective action recommendations based on actual releases.

Under these circumstances, the public risk reduction would be directly attributed to the decrease in public radiation exposure which results from a more rapid assessment of the radioactive releases (about a 2-hour savings in analysis time). There may also be a public risk reduction due to non-evacuation. This could result from better knowledge of the isotopic releases eliminating the need for evacuation (presumed to exist if release knowledge is based only on noble gas monitor data). Non-evacuation results in less evacuation-related risks (e.g., traffic accidents), the avoidance of which may outweigh the radiation exposure received. However, for this analysis, it is assumed that the public risk reduction results primarily from the first effect (decrease in exposure due to more rapid assessment).

While protective actions can be recommended based on effluent releases in progress, the probability for a core-melt scenario is such that actions would be recommended based on anticipated releases, prior to the actual release themselves. Under that assumption, monitoring effluent releases would have little or no impact on public risk and would be mainly for confirmation and quantification. This safety issue resolution would not impact core-melt accident frequency.

There are 134 plants affected by this issue: 71 operating (47 PWRs and 24 BWRs) and 63 planned (43 PWRs and 20 BWRs). It will be assumed that the average remaining plant life is 27.4 years for 44 BWRs and 28.8 years for 90 PWRs. The dose factors for PWR Release Categories 1 through 7 and BWR Release Categories 1 through 4 are assumed to be affected by the possible solution. From NUREG/CR-2800,[64] a 1% decrease in the dose factors results in an estimated total public risk reduction of 8,500 man-rem for all plants. Assuming a decrease in the dose factors of 0.5% for this issue, the estimated public risk reduction is 4,250 man-rem.

Cost Estimate

Industry Cost: The industry cost for equipment development, installation, support facilities, and construction is estimated at $600,000 per plant. Development of procedures, software, and calibration for the equipment is estimated to require 16 man-weeks of effort, with an additional 4 man-weeks of effort for the initial training of all licensee operators and health physics personnel. This is estimated to add $45,400 per plant to the implementation cost. Based on estimated costs of $645,000/plant for labor and equipment, the total industry cost for implementing the possible solution is (134 plants)($645,000/plant) or $86.5M.

The recurring industry operation and maintenance costs are estimated at 2 man-weeks/plant-yr for retraining, 1 man-week/plant-yr for calibration, and a reduction of 1 man-week/plant-yr (reduced laboratory analyses due to a fully automated system) for a net increase of 2 man-weeks/plant-yr at a cost of $4,540/plant-yr. As a result, industry costs for labor and material associated with operation and maintenance of the possible solution are estimated to be $17.2M.

The total industry cost associated with this issue is $(86.5 + 17.2)M or $103.7M.

NRC Cost: The NRC cost is assumed to be limited to implementation costs for development and plant installation. Since it is assumed that the new radiological monitoring systems would require no periodic inspection effort beyond that required for current systems, no additional NRC operation cost is envisioned. The NRC development costs include 1.5 man-year and $200,000 for research, criteria development, and engineering development for a total cost of $350,000. NRC administrative and technical effort associated with the review and approval of licensee submittals is estimated at 0.3 man-wk/plant for a total cost of $91,000 for all plants. Therefore, the total NRC cost associated with this issue is $441,000.

Value/Impact Assessment

Based on a total risk reduction of 4,250 man-rem, the value/impact score is given by:

$$S = \frac{4{,}250 \text{ man-rem}}{\$(103.7 + 0.441)\text{M}}$$

$$\cong 41 \text{ man-rem/\$M}$$

Other Considerations

It is anticipated that improvement of radiological monitoring of airborne effluents would have no significant impact on occupational risk. The dose required to install equipment would probably not exceed 0.5 man-rem, which is negligible compared to the typical 600 man-rem/yr required to operate a plant. Minor man-rem savings might occur under accident conditions due to better direction of field survey teams; however, such savings would be negligible compared to the 19,900 man-rem total associated with response and cleanup following an accident.

Based on an estimated occupational dose of 0.5 man-rem/plant for implementation of the possible solution in 71 operating plants, the total risk increase is 36 man-rem for all plants. Inclusion of this factor into the above calculation would reduce the value/impact score.

There is no accident avoidance cost for the resolution of this issue because improved radiological effluent monitoring systems would have no impact on accident frequency or cleanup and refurbishing costs.

CONCLUSION

This issue has a LOW priority ranking.

ITEM III.D.2.1(1): EVALUATE THE FEASIBILITY AND PERFORM A VALUE-IMPACT ANALYSIS OF MODIFYING EFFLUENT-MONITORING DESIGN CRITERIA

This item was evaluated in Item III.D.2.1 above and was determined to be LOW priority.

ITEM 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

This item was evaluated in Item III.D.2.1 above and was determined to be LOW priority.

ITEM III.D.2.1(3): REVISE REGULATORY GUIDES

This item was evaluated in Item III.D.2.1 above and was determined to be LOW priority.

ITEM III.D.2.2: RADIOIODINE, CARBON-14, AND TRITIUM PATHWAY DOSE ANALYSIS

The four parts of this item have been combined and evaluated together.

DESCRIPTION

Historical Background

This TMI Action Plan[48] item addressed the issue of further research for improving the understanding of radioiodine partitioning in nuclear power reactors and of the environmental behavior of radioiodine, carbon-14, and tritium following an accident and during normal operation.

Iodine isotopes are considered to be major contributors to the occupational and public dose during a LOCA, along with noble gases and fission products. Recent study in these areas is documented in NUREG-0772.[212] Major conclusions from NUREG-0772[212] state that: (1) uncertainties in predicting atmospheric release source terms are very large (at least a factor of 10), (2) source terms for certain accident sequences may have been overestimated in past studies, e.g., WASH-1400,[16] and (3) cesium iodide should be the predominant chemical form of iodine under severe accident conditions.

Safety Significance

The above conclusions indicate that the methodology and assumptions currently being used for evaluating radioiodine release may result in unrealistic estimates (e.g., Regulatory Guides 1.3[213] and 1.4[214]). Also indicated is that more research in aerosol behavior and fission product chemistry is needed in order to improve and support calculation methodology concerned with radioiodine partitioning, fission product behavior, etc.

Possible Solution

It could be assumed that further study will improve understanding of this issue and result in more realistic assumptions and methods for evaluating source terms, releases, and environmental behavior of radioiodine, carbon-14, and tritium following an accident. This research will not affect accident frequencies at nuclear power plants. However, the results of these studies are assumed to be used to revise the SRP[11] and Regulatory Guides.

It is then assumed that these Regulatory Guide revisions could result in reducing the size of current emergency planning zones (EPZs) from a 10-mile radius to a 2-mile radius. This assumption is based upon a reduction of source terms in a core-melt accident by a factor of 10. This results in reducing dose concentration at a particular distance from the nuclear reactor by a factor of 10 also. Assuming neutral weather conditions with a 30-meter-high plume, the offsite dose predicted at 2 miles from the accident scene, using the reduced source term assumption, would be the same as that currently predicted at 10 miles from the reactor.

CONCLUSION

Item III.D.2.2(1), related to the study of radioiodine, carbon 14, and tritium behavior at TMI-2, was completed in June 1981 and was documented in NUREG-0771[455] and NUREG-0772.[212] Items III.D.2.2(2), (3), and (4) called for a series of studies and evaluations of various radionuclide pathways and models followed, if necessary, by revisions to several SRP[11] Sections and Regulatory Guides. As part of the staff's task to prepare and publish a manual (Offsite Dose Calculation Manual) to be used by the NRC and industry to estimate individual and population doses during normal and accident conditions, Items III.D.2.2(2), (3), and (4) were assessed. This Offsite Dose Calculation Manual was prepared under Item III.D.2.5 and fully describes each of the theoretical models used to predict radionuclide transport.[149] Thus, Items III.D.2.2(2), (3), and (4) are covered under Item III.D.2.5.

ITEM III.D.2.2(1): PERFORM STUDY OF RADIOIODINE, CARBON-14, AND TRITIUM BEHAVIOR

This item was evaluated in Item III.D.2.2 above and has been RESOLVED with no new requirements.

ITEM III.D.2.2(2): EVALUATE DATA COLLECTED AT QUAD CITIES

This item was evaluated in Item III.D.2.2 above and was determined to be covered in Item III.D.2.5.

ITEM III.D.2.2.(3): DETERMINE THE DISTRIBUTION OF THE CHEMICAL SPECIES OF RADIOIODINE IN AIR-WATER-STEAM MIXTURES

This item was evaluated in Item III.D.2.2 above and was determined to be covered in Item III.D.2.5.

ITEM III.D.2.2.(4): REVISE SRP AND REGULATORY GUIDES

This item was evaluated in Item III.D.2.2 above and was determined to be covered in Item III.D.2.5.

ITEM III.D.2.3: LIQUID PATHWAY RADIOLOGICAL CONTROL

The four parts of this item have been combined and evaluated together.

DESCRIPTION

This TMI Action Plan[48] item is concerned with improving public radiation protection in the event of a nuclear power plant accident by improving the control of radioactivity released into the liquid pathway. This control can be accomplished by the application of various interdictive measures at the source of the release and/or along the liquid pathway. Techniques have been developed and are being used to evaluate the liquid pathway effects of an accident for each reactor site. Those sites that might require interdictive measures related to liquid pathway releases will be determined. Interdictive measures will be assessed as to their effectiveness in improving public radiation protection.

CONCLUSION

A liquid pathway analysis for Zion was completed by DE in 1980.[391] In addition to this, a liquid pathway analysis was performed for Indian Point. Both analyses were utilized in NUREG-0850.[390] A simplified analysis for liquid pathway studies (NUREG-1054)[658] was published in August 1984 and Section 7.1.1 of the Environmental Standard Review Plan (ESRP)[464] was drafted with no new requirements for licensees or applicants.[659, 660] ESRP Section 7.1.1 was finally published as NUREG-1165[838] in November 1985. Thus, this item was RESOLVED and no new requirements were established.[799]

ITEM III.D.2.3(1): DEVELOP PROCEDURES TO DISCRIMINATE BETWEEN SITES/PLANTS

This item was evaluated in Item III.D.2.3 above and has been RESOLVED with no new requirements.[799]

ITEM III.D.2.3(2): DISCRIMINATE BETWEEN SITES AND PLANTS THAT REQUIRE CONSIDERATION OF LIQUID PATHWAY INTERDICTION TECHNIQUES

This item was evaluated in Item III.D.2.3 above and has been RESOLVED with no new requirements.[799]

ITEM III.D.2.3(3): ESTABLISH FEASIBLE METHOD OF PATHWAY INTERDICTION

This item was evaluated in Item III.D.2.3 above and has been RESOLVED with no new requirements.[799]

ITEM III.D.2.3(4): PREPARE A SUMMARY ASSESSMENT

This item was evaluated in Item III.D.2.3 above and has been RESOLVED with no new requirements.[799]

ITEM III.D.2.4: OFFSITE DOSE MEASUREMENTS

ITEM III.D.2.4(1): STUDY FEASIBILITY OF ENVIRONMENTAL MONITORS

DESCRIPTION

This TMI Action Plan[48] item called for the staff to study the feasibility of environmental monitors capable of measuring real-time rates of exposures to noble gases and radioiodines. Monitors or samplers capable of measuring respirable concentrations of radionuclides and particulates were also considered. This activity supports proposed revisions to Regulatory Guide 1.97[55] (Item II.F.3).

CONCLUSION

The establishment of Regulatory Guide 1.97[55] requirements for fixed monitors for detecting unidentified releases was postponed pending the outcome of a feasibility study. This study was completed in April 1982.[188] Using this study as a basis, the staff concluded that environmental monitors of this nature are not practical and that proposed requirements for these monitors be dropped from consideration.[189] All required action on this item has been completed[382] and the issue was RESOLVED with no new requirements.

ITEM III.D.2.4(2): PLACE 50 TLDs AROUND EACH SITE

DESCRIPTION

This TMI Action Plan[48] item called for OIE to place 50 TLDs around each site in coordination with states and utilities. During normal operation, OIE quarterly reports from these dosimeters were to be provided to NRC, state, and federal organizations. In the event of an accident, the dosimeters could then be read at a frequency appropriate to the needs of the situation.

The specific objectives of this program were as follows:

(1) To establish preoperational, historical, baseline radiation dose levels, whenever possible, for each monitored facility
(2) To provide ongoing radiation dosimetry data during routine operations
(3) To provide postaccident radiation dosimetry to aid in assessment of population exposures and radiological impact
(4) To allow for independent verification of the adequacy of NRC licensees' environmental radiation monitoring programs
(5) To provide uniform treatment of dosimeters with respect to handling, shipping, calibrating, reading, and data processing for all monitored facilities in the United States
(6) To provide uniform, consistent environmental radiation monitoring data for use by the Congress, federal and state agencies, monitored facilities, and the public.

OIE completed installation of TLDs at all operating reactors in August 1980 in accordance with the TMI Action Plan schedule. A Direct Radiation Monitoring Network was established and a program for routine reporting was begun. The completion of these activities are described in an OIE memorandum.[236]

With the establishment of the NRC TLD Direct Radiation Monitoring Network, the installation of TLDs at all operating reactor sites, and the routine reporting of the TLD measurements, all work required by this item has been completed.[236,379] This item is related to improving the capability to make assessments of safety and, therefore, is considered a licensing issue.

CONCLUSION

This Licensing Issue has been resolved.

ITEM III.D.2.5: OFFSITE DOSE CALCULATION MANUAL

DESCRIPTION

Historical Background

This TMI Action Plan[48] item required that NRR prepare a manual to be used by the NRC and plant personnel to estimate maximum individual doses and popul tion doses during an accident.

Safety Significance

This issue does not affect core-melt frequencies or the amount of radioactivity released. Instead, it is intended to reduce the consequences of a major release by assuring that licensees have a rapid and sufficiently accurate method of estimating dose and that communication between licensees and the NRC is expedited by having a common standard calculation method for both.

Possible Solution

The proposed manual would include formulations with which to combine source term and meteorological measurements. This would determine offsite dose rates in a manner that would be standard among all parties making decisions on public protection and emergency response. Appendix 2 to NUREG-0654[224] establishes criteria for automated assessment of radiation doses in the event of an accident.

PRIORITY DETERMINATION

The assessment of this issue and its proposed resolution were performed by PNL.[64]

Frequency Estimate

The proposed solution to the issue does not affect accident frequencies. The frequencies for the various release categories given for Oconee and Grand Gulf were used unchanged in the value/impact calculation.

Consequence Estimate

The PNL experts judged that a 1% reduction in public dose (man-rem) might be expected as a result of having the offsite dose calculation manual available. We estimate the changes in consequences would be much less, 0.01% to 0.1%. Since all sequences would be affected and the risk from both PWRs and BWRs is about 210 to 250 man-rem/RY, the risk reduction is estimated to be 0.02 to 0.2 man-rem/RY.

Currently, there are 43 PWRs and 27 BWRs operating with cumulative experience of 350 RY and 260 RY, respectively. If we add to these the 36 PWRs and 21 BWRs under construction and assume a plant lifetime of 40 years, there are 2,810 PWR-years and 1,660 BWR-years in the future for a total of 4,470 RY. Therefore, the total risk reduction associated with this issue is (0.2)(4,470)man-rem or 894 man-rem.

Cost Estimate

Industry Cost: For the utilities, 4 man-weeks of training for implementation are assumed, since operators are now retrained periodically and this retraining could include dose calculation methods. This different method would not incur additional recurring costs. Thus, the total industry cost is estimated to be $7,700/plant or $0.98M for 127 plants.

NRC Cost: The NRC has already completed work on development of a portable computerized system for dose calculations to be used by the NRC Regional Offices. This is part of the program for NUREG-0654.[224] This program has been developed to the point of field trials for the computerized system. Based on the current development costs, an additional $125,000 to develop this package into a manual form for use by utilities will be assumed. It is estimated that NRC site representatives could spend a minimal amount of time (~2 days) to evaluate initial utility performance with the package. This is estimated to be $600/plant. The total NRC cost is approximately $200,000.

Value/Impact Assessment

Based on a total public risk reduction of 894 man-rem, the value/impact score is given by:

$$S = \frac{894 \text{ man-rem}}{\$(0.98 + 0.2)M}$$

$$= 758 \text{ man-rem/\$M}$$

CONCLUSION

Based on the value/impact score, the issue was identified as medium priority. However, since the prioritization was completed, the Offsite Dose Calculation Manual was published as NUREG/CR-3332[599] in September 1983. Thus, this item has been RESOLVED and no new requirements were issued.[598]

ITEM III.D.2.6: INDEPENDENT RADIOLOGICAL MEASUREMENTS

DESCRIPTION

This TMI Action Plan[48] item deals with independent radiological measurements, i.e., means of collecting data independently of the licensees' programs to do this. An OIE task force has developed a plan and requirements for upgrading the capability of Regional Offices to perform independent radiological measurements during routine inspections and emergency response operations. The objective of the upgrade is to achieve consistent capability among the regional offices, including standardization in major equipment items, such as mobile laboratory vans, gamma spectrum analysis equipment, radiation survey instrumentation, and air-sampling and monitoring devices.

Based on the recommendations of this task force, each Region was equipped with complete mobile laboratories.[235] In some cases, this represented upgrading certain equipment or purchasing new equipment. This action item required that revisions be made to the inspection program to include the upgrading of the independent radiological measurements. The program is included in the routine OIE program for review and revision of the inspection program. As new equipment needs are identified, the program will be revised and the equipment acquired.

With the upgrading of independent radiological measurements and the implementation of other recommendations made by the task force, all work required by this item has been completed.[235,379] This item is related to improving the NRC capability to make independent assessments of safety and, therefore, is considered a licensing issue.

CONCLUSION

This Licensing Issue has been resolved.

REFERENCES

11. NUREG-0800, "Standard Review Plan," U.S. Nuclear Regulatory Commission.

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.

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 Acccident," U.S. Nuclear Regulatory Commission.

57. NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," U.S. Nuclear Regulatory Commission, July 31, 1979.

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

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

149. Memorandum for J. Funches from R. Mattson, "Comments on Prioritization of Licensing Improvement Issues," February 2, 1983.

188. NUREG/CR-2644, "An Assessment of Offsite, Real-Time Dose Measurements for Emergency Situations," U.S. Nuclear Regulatory Commission, April 1982.

189. Memorandum for K. Goller from R. Mattson, "Proposed Changes to Regulatory Guide 1.97," July 29, 1982.

212. NUREG-0772, "Technical Bases for Estimating Fission Product Behavior During LWR Accidents," U.S. Nuclear Regulatory Commission, June 1981.

213. Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," U.S. Nuclear Regulatory Commission, June 1974.

214. Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, June 1974.

224. NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," U.S. Nuclear Regulatory Commission, November 1980.

235. Memorandum for H. Denton from R. DeYoung, "TMI Action Plan Items Still Pending," June 10, 1982.

236. Memorandum for W. Dircks from R. DeYoung, "TMI Action Plan - Completed Items," June 30, 1982.

379. Memorandum for H. Denton from R. DeYoung, "Draft Report on the Prioritization of Non-NRR TMI Action Plan Items," January 1983.

382. Memorandum for W. Minners from R. Mattson, "Schedules for Resolving and Completing Generic Issues," January 21, 1983.

384. Memorandum for T. Speis from R. Vollmer, "Schedules for Resolving and Completing Generic Issues," February 1, 1983.

390. NUREG-0850, "Preliminary Assessment of Core Melt Accidents at the Zion and Indian Point Nuclear Power Plants and Strategies for Mitigating Their Effects," U.S. Nuclear Regulatory Commission, November 1981.

391. Memorandum for E. Reeves from J. Knight, "Zion Liquid Pathway Analysis," August 8, 1980.

455. NUREG-0771, "Regulatory Impact of Nuclear Reactor Accident Source Term Assumptions," U.S. Nuclear Regulatory Commission, June 1981.

464. NUREG-0555, "Environmental Standard Review Plans for the Environmental Review of Construction Permit Applications for Nuclear Power Plants," U.S. Nuclear Regulatory Commission.

598. Memorandum for W. Dircks from H. Denton, "Closeout of TMI Action Plan Task III.D.2.5, 'Offsite Dose Calculation Manual,'" January 17, 1984.

599. NUREG/CR-3332, "Radiological Assessment - A Textbook on Environmental Dose Analysis," U.S. Nuclear Regulatory Commission, September 1983.

659. Memorandum for H. Denton from R. Vollmer, "ESRP 7.1.1 'Environmental Impacts of Postulated Accidents Involving Radioactive Materials - Releases to Groundwater,'" September 25, 1984.

660. Memorandum for W. Dircks from H. Denton, "Generic Issue III.D.2.3 'Liquid Pathway Radiological Control,'" October 29, 1984.

799. Memorandum for W. Dircks from H. Denton, "Resolution of Generic Issue III.D.2.3--Liquid Pathway Studies," August 28, 1985.

838. NUREG-1165, "Environmental Standard Review Plan for ES Section 7.1.1," U.S. Nuclear Regulatory Commission, November 1985.

TASK IV.E: SAFETY DECISION-MAKING

The objective of this task is to develop plans for an integrated program of safety decision-making. These plans include: (1) an expanded program of regulatory research covering methodologies for making safety decisions and safety-cost tradeoffs, with application both to decisions regarding the overall risk of nuclear power plants and the nuclear fuel cycle and to specific licensing and inspection decisions; (2) early resolution of safety issues after they are identified, including application of the decisions to operating reactors, reactors under construction, and standard designs; (3) elimination of repetitive consideration of identical issues at several stages of the licensing process; (4) expanded use of rulemaking to implement safety criteria developed as a result of the various Task Action Plans; and (5) improved and expanded systematic assessments of operating reactors.

ITEM IV.E.1: EXPAND RESEARCH ON QUANTIFICATION OF SAFETY DECISION-MAKING

DESCRIPTION

This issue is described in NUREG-0660[48] as follows:

"The purpose of this task is to proceed toward better quantification of safety objectives, including safety-cost tradeoffs. The concept will use ongoing research that one might quantify risk and possible application of formal decision-making techniques to the regulatory environment. Future programs will build on the risk assessment and systems reliability work currently underway and incorporate a better assessment of common-mode and human failures. Safety objectives will be developed for components and systems, and eventually these might be amalgamated into a more tightly bounded, quantitative safety standard, as opposed to a safety objective having fairly large inherent uncertainties."

The approach to the resolution of this item is also outlined in NUREG-0660[48] as follows:

(1) RES will assemble a research task force from a wide variety of professional disciplines. The task force will formulate several possible sets of numerical criteria using different technical approaches. The formation of the research task force and the conduct of its meetings are being coordinated through IEEE with cooperation from other professional societies.

(2) BNL has been contracted to independently formulate criteria to investigate the implications of safety criteria and to determine the impact of attempting to satisfy such criteria.

(3) Decision theory and survey methods for obtaining criteria are being investigated as extensions of previous projects on risk analysis. These methods can provide a separate approach to obtain acceptable risk criteria.

(4) Negotiations are underway with various governmental and private agencies for information on proposed criteria. In addition, letters have been sent to several hundred individuals announcing the project and requesting their contributions.

(5) To assure that the criteria receive rigorous peer review, negotiations are underway with the National Science Foundation, the National Academy of Sciences, and the American Statistical Association.

The current accomplishments include completion of NUREG/CR-1614,[275] NUREG/CR-1539,[276] NUREG/CR-1930,[277] NUREG/CR-1916,[278] and NUREG/CR-2040.[279] The current status is such that PNL, ORNL, BNL, ANL, IEEE, NRC (Office of Policy Evaluation), and the ACRS are completing various elements of the overall program. These activities will develop and exhibit approaches with which to better factor risk evaluation into NRC decision-making regarding reactor plant safety. This issue does not appear to have a direct effect on public risk reduction or to have any industry cost directly associated with its resolution. Therefore, it is a licensing issue.

CONCLUSION

The item is a Licensing Issue.

ITEM IV.E.2: PLAN FOR EARLY RESOLUTION OF SAFETY ISSUES

DESCRIPTION

This TMI Action Plan[48] item required NRR, in consultation with other appropriate offices, to develop a plan for the early identification, assessment, and resolution of safety issues. This item is related to the establishment and implementation of an NRC program to identify and resolve safety issues and, therefore, is considered a licensing issue.

CONCLUSION

The plan was presented in SECY-81-513[1] on August 25, 1981 and is currently being implemented by SPEB. Thus, this Licensing Issue has been resolved.

ITEM IV.E.3: PLAN FOR RESOLVING ISSUES AT THE CP STAGE

DESCRIPTION

According to NUREG-0660,[48] NRR and ELD transmitted a consent calendar item to the Commission on February 14, 1980, entitled "Response to Staff Requirements Memorandum (Affirmation Session 79-40) With Respect to Post-CP Design and Other Changes," SECY-80-90. This paper discussed five options regarding the establishment of construction requirements. The recommendation of this consent paper is to publish an advance notice of public rulemaking to obtain comments on these options. After receipt of public comment on the above, the staff will prepare a plan to implement methods to resolve as many issues as possible at the construction permit stage before major financial commitments in construction occur.

An advanced notice of rulemaking was published in the Federal Register in December 1980 with a public comment period ending on February 9, 1981. On August 18, 1981, the Director of the Division of Risk Analysis sent a memo to distribution proposing an approach to the Rule and requested examples of the types of characteristic alterations representing post-CP changes. The draft of the Rule is currently being reviewed.

In view of the intent of this item, it is concluded that its resolution does not have a direct effect on public risk reduction and is, therefore, considered to be a licensing issue.

CONCLUSION

The resolution of this Licensing Issue is available.

ITEM IV.E.4: RESOLVE GENERIC ISSUES BY RULEMAKING

DESCRIPTION

This TMI Action Plan[48] item states that the NRC will undertake the additional task of developing a program for reviewing new criteria before their promulgation to determine whether rulemaking would be the desirable means of implementation. The intent will be to implement new NRC criteria by rule, wherever feasible and timely, instead of by license changes, orders, or changes in regulatory guides.

This item does not have a direct effect on public risk reduction nor is any industry cost associated with the completion or implementation of the issue resolution.

CONCLUSION

This item is a Licensing Issue.

ITEM IV.E.5: ASSESS CURRENTLY OPERATING REACTORS

DESCRIPTION

Historical Background

As part of developing plans for an integrated program of safety decisionmaking, NRR, in consultation with other appropriate offices, will develop a plan for approval by the Commission for the systematic assessment of the safety of all operating reactors. Development of such a plan will take into account the SEP, the ACRS comments on the program, the IREP plan, and ongoing TMI lessons-learned activities. This value/impact assessment of Item IV.E.5 deals with the work under the SEP. Value/impact assessments of IREP and NREP are presented in Items II.C.1 and II.C.2, respectively.

SEP is now reviewing the 10 oldest plants against current licensing review safety criteria, including the SRP, to provide the basis for integrated and balanced backfit decisions. This review is nearly complete and, therefore, is not part of this assessment. The next SEP phase involves evaluation of 11 additional plants. In this next phase, PRA evaluations will be coordinated with the deterministic review method (review against current licensing safety criteria). The PRA will be done as part of NREP (TMI Action Plan Item II.C.2).

Possible Solutions

As safety-related problems are identified for each plant, resolutions are developed using procedural and administrative changes, possible credit for non-safety systems where justified, and hardware backfits as necessary to reduce risk levels. The process used to decide appropriate corrective actions employs the judgment of a team of NRC staff familiar with each plant.

PRIORITY DETERMINATION

This priority determination uses potential risk reduction analyses and cost estimate information provided by PNL.[64]

Frequency/Consequence Estimate

This public risk reduction analysis for SEP considers only the 11 additional plants currently proposed to be reviewed in the first group of Phase III plants, since much of the review of the first 10 plants in Phase II has been performed. The 11 plants consist of 7 PWRs and 4 BWRs with estimated average remaining lives of 24 and 22 years, respectively. In Item II.C.2 (NREP), it is estimated that an overall core-melt frequency reduction of 2×10^{-4}/RY could be achieved for one-third of the plants to be reviewed under NREP. Although the NREP evaluation of these plants will identify some areas of potentially high risk, the NREP methods do not address areas such as external events and structural design which are included in the SEP deterministic review. For this issue, it is assumed that the risk reduction estimated for NREP could be achieved by the SEP considering only the benefit resulting from using the deterministic review method for external events and other issues outside the scope of PRAs (e.g., adequacy of design, structural issues, and design errors).

Using the base case core-melt frequency and the base case public risk for each type plant, and assuming a population of 340 persons per square mile over an area having a 50 mile radius, the average risk per core-melt is 2.5×10^6 man-rem for PWRs and 6.8×10^6 man-rem for BWRs.

Using the average risk value and the assumption stated above that the deterministic review method can achieve the core-melt frequency reduction estimated for NREP for one-third of the plants reviewed, we can estimate the potential reduction for the SEP Phase III as follows:

PWRS

$$\text{Risk Reduction} = (2.5 \times 10^6 \text{ man-rem/core-melt})(2 \times 10^{-4} \text{ core-melt/RY})$$
$$= 500 \text{ man-rem/RY}$$

BWRs

$$\text{Risk Reduction} = (6.8 \times 10^6 \text{ man-rem/core-melt})(2 \times 10^{-4} \text{ core-melt/RY}) = 1{,}360 \text{ man-rem/RY}$$

Summed over the average remaining plant life for the 11 plants proposed, the total public risk reduction is calculated to be approximately 80,000 man-rem.

Cost Estimate

Industry Cost: Based on SEP studies completed to date, the following costs per plant are estimated: up to $2M for engineering studies to identify areas of plant modification and $2M to $20M to design and install modifications.

For purposes of this analysis, assume a conservative implementation cost per plant of $2M for engineering studies at each of the 11 plants plus $10M average design and installation (including capital equipment cost) at one-third of the plants. For 11 plants, the total industry cost is $[(11)(2) + (1/3)(11)(10)]M or $55M.

NRC Cost: Based on past studies, NRC staff effort has totaled 10 man-yr/plant plus $700,000 contract technical support per plant. Thus, total development and implementation cost, at $100,000/man-year, is:

(10 man-years/plant)($100,000/man-yr) + ($700,000/plant)(11 plants) = $19M.

Assuming NRC staff effort for review and inspection of plant modifications at one-third of the plants is 0.5 man-wk/RY and the average remaining life of these plants is 23 years, then the total plant review cost is:

(0.5 man-wk/RY)($2,000/man-wk)[(1/3)(11)(23)RY] = $0.1M.

Value/Impact Assessment

Based on a public risk reduction of 80,000 man-rem, the value/impact score is given by:

$$S = \frac{80{,}000 \text{ man-rem}}{\$(55 + 19)\text{M}}$$

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

Other Considerations

If the cleanup of an accident is assumed to require 19,900 man-rem and the same assumption on accident frequency reduction is retained, the total reduction in occupational exposure would be 170 man-rem. An estimate of the occupational exposure to implement any changes cannot be made without identifying the specific changes. However, there would likely be some increase in occupational exposure, but it would be small compared to the public risk reduction.

An additional consideration is that plant damage is estimated to be \$1,650M per plant for core-melt. Thus, total averted plant damage for one-third of the plants with a reduced core-melt frequency could be

$$(\$1,650M)(2 \times 10^{-4}/RY)[(1/3)(11)(23)RY] = \$28.9M$$

Uncertainties

Since the 11 plants considered are older plants, it is possible that the assumed 10^{-4}/RY risk reduction may be achieved for more than one-third of the 11 plants as assumed, thus resulting in greater risk reduction with an associated increase in implementation cost. However, the value/impact score would not change appreciably.

CONCLUSION

The value/impact score indicates a medium priority. However, the potentially large, though uncertain, risk reduction of nearly 80,000 man-rem justified a high priority ranking.

Work completed by the staff on this item was closely related to the accomplishments under Item II.C.2. Whereas Item II.C.2 called for the initiation of IREP studies (i.e. plant-specific PRAs) on all remaining operating reactors, Item IV.E.5 called for the development of a plan for the systematic assessment of the safety of all operating reactors. The Integrated Safety Assessment Program (ISAP), presented in SECY-84-133[814] and SECY-85-160,[815] provided for a comprehensive review of selected operating reactors to address all pertinent safety issues and to provide an integrated cost-effective implementation plan for making needed changes. Under ISAP, each plant would be subject to an integrated assessment of safety topics, a probabilistic safety assessment, and an evaluation of operating experience.

NRC guidance, as described in the Severe Accident Policy Statement (see Item II.B.8), states that OLs will be expected to perform plant-specific PRAs in order to discover instances of particular vulnerability to a core-melt or poor containment performance, given a core-melt. Thus, this item was RESOLVED and no new requirements were established.[816]

REFERENCES

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

275. NUREG/CR-1614, "Approaches to Acceptable Risk: A Critical Guide," U.S. Nuclear Regulatory Commission, September 1980.

276. NUREG/CR-1539, "A Methodology and a Preliminary Data Base for Examining the Health Risks of Electricity Generation from Uranium and Coal Fuels," U.S. Nuclear Regulatory Commission, August 1980.

277. NUREG/CR-1930, "Index of Risk Exposure and Risk Acceptance Criteria," U.S. Nuclear Regulatory Commission, February 1981.

278. NUREG/CR-1916, "A Risk Comparison," U.S. Nuclear Regulatory Commission, February 1981.

279. NUREG/CR-2040, "A Study of the Implications of Applying Quantitative Risk Criteria in the Licensing of Nuclear Power Plants in the U.S.," U.S. Nuclear Regulatory Commission, March 1981.

814. SECY-84-133, "Integrated Safety Assessment Program (ISAP)," March 23, 1984.

815. SECY-85-160, "Integrated Safety Assessment Program - Implementation Plan," May 6, 1985.

816. Memorandum for W. Dircks from H. Denton, "Close-out of Generic Issues II.C.2 'Continuation of IREP,' and IV.E.5 'Assess Currently Operating Reactors,'" September 25, 1985.

ITEM B-17: CRITERIA FOR SAFETY-RELATED OPERATOR ACTIONS

DESCRIPTION

Historical Background

Current plant designs are such that reliance on the operator to take action in response to certain transients is necessary. In addition, some current PWR designs require manual operations to accomplish the switchover from the injection mode to the recirculation mode following a LOCA. The required time for the ECCS realignment operations is dependent on pipe break size and the operation must be accomplished before the inventory in the borated water storage tank is depleted.

This NUREG-0471[3] item involves the development of a time criterion for safety-related operator actions (SROA) including a determination of whether or not automatic actuation will be required. The evaluation of this issue includes Issue 27 contained in Section 1 of this report.

Safety Significance

Development and implementation of criteria for SROA would result in the automation of some actions currently performed by operators. The use of automated redundant safety-grade controls in lieu of operator actions is expected to reduce the frequency of improper action during the response to or recovery from transients and accidents by removing the potential for operator error. This in turn could reduce the expected frequency of core damaging events and, therefore, reduce the public risk accordingly.

Possible Solutions

Plants would be required to perform task analysis, simulator studies, and analysis and evaluation of operational data to assess current ESF and safety-related control system designs for conformance to new criteria. Where nonconformance is identified, modification to existing designs and hardware would be required. For plants at the CP stage of review, changes and additions to the ESF control systems are anticipated but replacement equipment costs are not anticipated.

PRIORITY DETERMINATION

Assumptions

In the analysis of this issue the following major assumptions were made:

(a) Operator error comprises 40% of total plant risk

(b) 10% of short-term emergency response actions are taken by operators

(c) 50% of long-term emergency response and recovery actions are taken by operators

(d) One half of operator actions now taken in the short-term would be automated

(e) 20% of operator actions now taken in the long term would be automated

(f) failure rate of automated ESF controls is on the order of 10^{-4}/demand

(g) failure rate of trained and practiced operators is on the order of 10^{-2}/demand in the highly stressed short-term period and 10^{-3}/demand in the less stressful long term period.

Frequency/Consequence Estimate

Using WASH-1400[16] frequencies, current estimates of the doses to be expected for the various PWR and BWR release categories, and the projected population and remaining operating life of PWRs and BWRs, a total plant risk of 2.8×10^5 man-rem was determined. Operator contribution to total plant risk (40%) is thus estimated to be 1.12×10^5 man-rem. Of this risk, one half was attributed to the short-term response period and one half to the long-term response period.

Using the above stated assumptions on operator error and automated control system failure rates and the portion of short-term and long-term actions allocated to the operator, the short-term potential public risk reduction for completion and implementation of SROA criteria was estimated to be 2.8×10^3 man-rem. Resolution of the issue was estimated to provide a potential long-term public risk reduction of 5.0×10^3 man-rem. Thus, a total potential public risk reduction of 7.8×10^3 man-rem is estimated and an average potential public risk reduction of 50 man-rem/reactor is estimated. Assuming an average core-melt consequence of 5×10^6 man-rem/event, a potential reduction of core-melt frequency of 3.8×10^{-7}/RY and 5.4×10^{-5}/reactor is estimated.

Cost Estimate

Industry Cost: Designers and/or operators of all plants were assumed to perform a design review and analysis of their existing ESF and safety-related control systems and prepare modification packages for NRC review and approval. Comparison of existing designs to new criteria, preliminary design, final design, and NRC documentation are estimated to require 1 man-year per plant since most plants are multiple unit designs. Thus, the design costs for 143 plants are estimated to be $14.3M.

Equipment costs were divided into two groups: (1) older plants, and (2) recent and future plants. Recent and future plants are separated because of current requirements for the automation of ECCS switchover to recirculation and automatic initiation of AFW systems. Backfit equipment and installation costs for older plants were estimated at $500,000/plant while the newer plants are estimated at $250,000/plant. Using the above breakdown on newer and older plants, a total equipment and installation cost of $53.7M is estimated. No additional recurring costs were estimated for operational maintenance and surveillance of the automated control systems since maintenance and surveillance would have been required for the manual control systems which are assumed to be replaced.

NRC Cost: The FY-1983 RES contract (FIN B0421) with ORNL includes efforts by ORNL and its subcontractor (General Physics Corp.) to complete operator task analyses, simulator studies, operational data collection and analysis, and the development and recommendation of SROA criteria. This work is being pursued as part of Item I.A.4.2, Long-Term Training Simulator Improvements.[48] Completion of the above efforts, review of the above and development of SROA criteria, review and approval of new criteria, orders to licensees and applicants, and review and approval of licensee and applicant responses are estimated to cost $4M over the next 5 years.

Thus, the total cost associated with the solution to this issue is estimated to be $(4 + 14.3 + 53.7)M or $72M.

Value/Impact Assessment

Based on a total potential public risk reduction of 7.8×10^3 man-rem, the value/impact score is given by:

$$S = \frac{7.8 \times 10^3 \text{ man-rem}}{\$72\text{M}}$$

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

Other Considerations

Uncertainties for this analysis are very large due to the subjective nature of the approach to operator error reduction. It should be acknowledged that a more deterministic design-specific analysis, which might be performed after the Item I.A.4.2 SROA criteria recommendations are developed, could well alter the value/impact score for this issue by one to two orders of magnitude in either direction.

CONCLUSION

The value/impact score calculated is indicative of a medium priority ranking. It was recommended that, after the conclusion of the SROA criteria development efforts on Item I.A.4.2, a more rigorous analysis should be performed to reassess the value/impact associated with the adoption and implementation of specific SROA requirements which are not currently available. However, with the publication of the HFPP in NUREG-0985, Revision 1,[651] this item was determined to be covered in Issue HF01.4.3.

REFERENCES

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

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.

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

651. NUREG-0985, Revision 1, "U.S. Nuclear Regulatory Commission Human Factors Program Plan," U.S. Nuclear Regulatory Commission, September 1984.

ITEM B-58: PASSIVE MECHANICAL FAILURES

DESCRIPTION

Historical Background

This NUREG-0471[3] task involves a review of valve failure data in a systematic manner to verify the staff's present judgment regarding the likelihood of passive mechanical valve failures, to categorize these and other valve failures as to expected frequency, to specify acceptance criteria, and to det rmine if and how the results of this effort should be applied in licensing reviews. The issue is related to a number of other issues dealing with valve reliability: Item C-11, "Assessment of Failure and Reliability of Pumps and Valves"; Item II.D.2, "Research on Relief and Safety Valve Test Requirements"; and Item II.E.6.1, "In-Situ Testing of Valves - Test Adequacy Test Study."

Item C-11, in particular, is aimed at active failure of pumps and valves. Valve failure data collected at the Nuclear Safety Information Center were studied to identify failure frequency for active failure mechanisms.[102] These same data are examined here to identify passive failure mechanisms. The distinction is made here that active failures typically occur during valve operation while passive failures occur over a period of time, going unnoticed as the valve is rendered inoperable. Detection of failure then occurs after valve operation is demanded.

Safety Significance

In view of the fact that safety-related systems contain about 500 valves, passive failures present a potentially significant safety concern because the effects on safety-related systems can be so widespread.

Possible Solution

The solution to this safety issue is a program to investigate these valve failures and the operation of a valve maintenance program, including the replacement of valves as necessary over the life of the plant.

PRIORITY DETERMINATION

Frequency/Consequence Estimate

In an evaluation of this issue by PNL,[64] passive valve failure was noted to be due primarily to crud and corrosion which caused deterioration of valve function over a period of time. Based on the available data,[102] it was noted that the average number of hardware-related failures for BWRs and PWRs were 17% and 18%, respectively, of all valve failures. Over the life of existing plants, the average hardware-related passive failures represent about 12% of all valve failures. These data [102] also indicate that the failure rates for passive mechanical failures is 1.3/RY and 0.36/RY for BWRs and PWRs, respectively.

It is assumed that a 50% reduction in passive mechanical failures can be achieved by the resolution of this issue. This would result in a reduction in the average of hardware-related failures of 6% and a reduction in the failure rate of 0.65/RY and 0.18/RY for BWRs and PWRs, respectively.

Risk reduction is calculated for a representative PWR (Oconee 3) in which the affected parameters in the accident sequences are those which contain valves with hardware failure modes.[64] The base case public risk reduction was estimated by PNL to be less than 1 man-rem/RY for BWRs and PWRs. Therefore, the total public risk reduction is estimated to be less than 4,000 man-rem.[64] The occupational risk is increased by virtue of the implementation of this issue (+300 man-rem) but the exposure during operation and maintenance is reduced because of improved valve performance (-1,140 man-rem). The net change in occupational dose due to the resolution of this issue is -840 man-rem.

Cost Estimate

Based on the judgment of the PNL staff,[64] it is assumed that 13 valves will be replaced in BWRs and 4 valves replaced in PWRs during the implementation of the solution to this issue. (It is noted here that the final priority ranking of this issue is relatively insensitive to this assumption). Assuming that 24 man-hr/valve replacement is required, a total of 313 man-hrs and 96 man-hrs for the work of implementation in a radiation zone is calculated for BWRs and PWRs, respectively.

For backfit plants, it is assumed that the work time spent in radiation zones represents 20% of the total utility staff commitment to this issue. With administrative and engineering support, the total labor estimated is:

$$\text{BWR:} \quad \text{Labor} = \frac{1}{20\%} \quad \frac{312 \text{ man-hrs/plant}}{40 \text{ man-hrs/man-wk}} = 39 \text{ man-wk/plant}$$

$$\text{PWR:} \quad \text{Labor} = \frac{1}{20\%} \quad \frac{90 \text{ man-hrs/plant}}{40 \text{ man-hrs/man-wk}} = 12 \text{ man-wk/plant}$$

Backfit equipment is assumed to consist of 13 valves/BWR and 4 valves/PWR at a cost of $30,000/valve. Work will presumably be conducted during normal outages so that no additional downtime is foreseen.

It is also assumed that the nuclear industry will fund research totaling $500,000, a cost spread over all 134 plants. The intention of this program is to identify those elements that contribute significantly to passive valve failures so that they can be better controlled in the future.

The total costs per plant for implementation of the solution to the issue is:

Item	Cost ($/Plant)			
	BWR		PWR	
	Backfit	Forward-Fit	Backfit	Forward-Fit
Labor	88,500	-	27,200	-
Equipment	390,000	-	120,000	-
Research	3,700	3,700	3,700	3,700
	482,000	3,700	150,900	3,700

For 24 backfit and 20 forward-fit BWRs and 47 backfit and 43 forward-fit PWRs, the total industry implementation cost is $19M, based on a labor rate of $2,270/man-wk.

For operation and maintenance, the resolution of the safety issue is assumed to reduce the labor, equipment, and outage time attributable to passive valve failures. The labor and equipment requirements prior to resolution of the safety issue are as follows (note that the labor estimate of 24 man-hr/failure is increased by a factor of 5 to 120 man-hr/failure to include support labor, such as engineering and administration):

Labor

BWRs: (1.3 failures/RY)(120 man-hr/failure) = 3.9 man-wk/RY

PWRs: (0.36 failures/RY)(120 man-hr/failure) = 1.1 man-wk/RY

Equipment

BWRs: 1.3 valve replacements/RY at $30,000/valve

PWRs: 0.36 valve replacements/RY at $30,000/valve

Active failures of pumps and valves are estimated to account for 10% of the average 60 days/RY of routine downtime at a plant, or 6 days/RY. Dividing this equally between pump and valve failures, one can attribute 3 days/RY of downtime to active valve failures. Active valve failures were reported at rates of 639 failures in 140 RY (BWRs), or 4.6/RY, and 678 failures in 190 RY (PWRs), or 3.6/RY.[102] If the amount of downtime attributable to active valve failures is assumed proportional to their failure rates, then it follows that the amount of downtime attributable to passive valve failures will be proportional to the ratio of passive to active valve failure rates, or (1.3/4/6) = 0.28 for BWRs and (0.36/3.6) = 0.10 for PWRs. Thus, prior to safety issue implementation, the downtime attributable to passive valve failures is assumed to be as follows:

BWRs: (0.28)(3 days/RY) = 0.84 day/RY

PWRs: (0.10)(3 days/RY) = 0.30 day/RY

Assuming that the resolution of the safety issue reduces the passive valve failure rate by 50%, the following reductions in labor, equipment and down-time for operation and maintenance result:

	BWR	PWR
Labor (man-wk/RY)	2.0	0.55
Equipment (valve replacements/RY)	0.65	0.18
Downtime (days/RY)	0.42	0.15

The reductions in the per plant industry costs (indicated by the negative sign) for operation and maintenance is as follows:

	BWR	PWR
Labor (at $2,270/man-wk)	-$4,500/RY	-$1,200/RY
Equipment (at $30,000/valve)	-$19,500/RY	-$5,400/RY
Downtime (at $300,000/day)	-$126,000/RY	-$45,000/RY
	-$150,000/RY	-$51,600/RY

Based on average plant lifetimes of 28.8 yrs and 27.4 yrs for BWRs and PWRs, respectively, the total industry cost for operation and maintenance of this program is a fairly large estimated savings of $315M resulting principally from the reduction in reactor downtime.

The direct costs for the implementation and development of this safety issue are as follows:

Industry Implementation Cost	=	$19,000,000
NRC Development Cost	=	$50,000
Total	=	$19,050,000

Value/Impact Assessment

Based on the estimated risk reduction of less than 4,000 man-rem, the value/impact score is given by:

$$S < \frac{\$4{,}000\ \text{man-rem}}{\$19.05\text{M}}$$

$$< 210\ \text{man-rem/\$M}.$$

CONCLUSION

Based on the value/impact score of less than 210 man-rem/$M and a public risk reduction of less than 4,000 man-rem, this issue would have warranted a low to medium priority ranking. However, in view of the potentially large industry savings of approximately $300M that could accrue from reduced maintenance and reduced downtime, the issue was judged to be medium priority.

In pursuing a resolution to this issue, NRR recognized the existence of the Nuclear Plant Aging Research (NPAR) program that was being conducted by RES. Systematic studies under this program were to be performed to: (1) identify aging and service wear effects associated with mechanical components that could impair plant safety, and (2) identify techniques that will be effective in determining aging and service wear effects, prior to loss of safety function, so that proper maintenance and timely repair or replacement can be implemented. Although the NPAR program is intended to encompass many component types, it is envisioned to include various safety-related valve types and pump components.

RES intends to evaluate LWR operating experience and identify aging trends. One of the specific benefits cited is improved reliability and availability.

NRR evaluated the NPAR program and concluded that it generally encompasses the scope of the program inferred by Items B-58 and C-11. When this program is completed, it is expected that recommendations will be made by RES for maintenance, repair, or replacement according to component type. At that time, these recommendations will be grouped into manageable tasks and considered by NRR for possible changes to regulatory requirements. Thus, this issue was RESOLVED and no new requirements were established.[863]

REFERENCES

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

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

102. NUREG/CR-0848, "Summary and Bibliography of Operating Experience with Valves in Light-Water-Reactor Nuclear Power Plants for the Period 1965-1978," U.S. Nuclear Regulatory Commission, August 1979.

863. Memorandum for T. Speis from H. Denton, "Closeout of Generic Issues B-58 and C-11," July 9, 1985.

ITEM C-11: ASSESSMENT OF FAILURE AND RELIABILITY OF PUMPS AND VALVES

DESCRIPTION

Historical Background

The operating experience of nuclear power plants indicates that a number of valves, valve operators, and pumps fail to operate as specified in the technical specifications either under testing conditions or when they are called upon to perform. Most of these occurrences relate to valve leakage, valve actuation, and safety/relief valve operation outside their operational bounds. The main steam isolation, safety, and solenoid valves caused the most frequent abnormal occurrences in safety-related systems. Valve malfunctions can cause forced outages of operating plants. It is noted that about 10% of all outage time can be attributed to the malfunction of the critical pumps and valves within the plant. Of primary interest are outages caused by the main steam isolation and safety/relief valves.

The principal activity under this NUREG-0471[3] task will be the evaluation of active pumps and valves with respect to their operability and reliability under accident loading, i.e., LOCA and SSE, and implement a corrective action program specifically directed toward improved design and fabrication of active pumps and valves.

Safety Significance

Unreliability of active valves and pumps in nuclear plant safety systems contributes to the risk associated with postulated core-melt accident sequences.

Possible Solution

Resolution of this issue will serve to identify active pumps and valves that need redesign and replacement. Other issues related to this issue and whose results will supplement the equipment identification and redesign process of this issue are as follows: Issue 23, "Reactor Coolant Pump Seal Failures"; Issue 54, "Valve Operator-Related Events Occurring During 1978, 1979, and 1980"; Item B-55, "Improved Reliability of Target Rock Safety-Relief Valves"; and Item II.E.6.1, "In-Situ Testing of Valves - Test Adequacy Study." The reduction in public risk will result from a decreased probability of valve and pump failure.

PRIORITY DETERMINATION

Information provided by PNL[64] on potential risk reduction and costs was used to determine the priority of this issue.

Frequency Estimate

Oconee 3 and Grand Gulf are selected as the base case PWR and BWR, respectively, with estimated base case core-melt frequencies of 8.2×10^{-5}/RY and 3.7×10^{-5}/RY, respectively. It is assumed that this issue affects accident sequences and base case frequencies as follows: (1) In PWRs, all the core-melt accident sequences except three directly involve active pumps and valves and, thus, are assumed to be affected; (2) Interfacing system LOCA and loss of AC power sequences are not directly affected; and (3) In BWRs, all accident sequences involve active pumps and are thus assumed to be affected.

NUREG/CR-0848[102] summarizes the LERs relating to valve failures filed during the period 1965-1978. The tabular data provided was used to estimate the reduction in number of reports due to resolution of this issue. It was assumed that administrative, installation, maintenance, and operator error would not be affected (i.e., not directly applicable to failure due to hardware malfunction) and that, due to issue resolution, design and fabrication problems resulting in valve failures would be reduced. By decreasing the number of valve failures due to design error and fabrication error by 25%, fatigue failure (assumed to be a direct result of design error) by 25%, and all inherent causes by 10%, the total number of projected reports would be reduced by 9% in BWRs and PWRs. Therefore, it was assumed that the overall probability of failure of valves for both PWRs and BWRs due to issue resolution was reduced by 9%. This assumption was also applied to pumps.

Affected parameters include all elements of dominant minimal cut sets relating to active pumps and valves. The assumed valve and pump reduced failure probability was used to calculate the reduction in core-melt frequencies for affected accident sequences. The reduced frequencies are estimated to be 10^{-5}/RY for PWRs and 4×10^{-6}/RY for BWRs.

Consequence Estimate

Assuming typical midwest site meteorology, a uniform population density of 340 persons per square mile within a 50-mile radius, and the average releases from all of the WASH-1400[16] release categories, the risk reduction is estimated to be 19 man-rem/RY and 22 man-rem/RY for PWRs and BWRs, respectively.

This analysis assumes resolution of this issue will affect 134 plants including backfit (operating) and forward-fit PWRs and BWRs. It also assumes that it will require at least 5 years to redesign, fabricate, and install improved-design active valves and pumps. By that time, it is estimated that the affected plants and their average remaining life will be as follows:

	Plants	Remaining Lifetime (yrs)	Plant-Years (RY)
PWRs			
(a) Forward-fit	7	30	210
(b) Backfit	83	24.8	2,060
Total:	90		2,270
BWRs			
(a) Forward-fit	4	30	120
(b) Backfit	40	23	920
Total:	44		1,040

The public risk reduction for all plants for their remaining life is:

(19 man-rem/RY) (2,270 RY) + (22 man-rem/RY) (1,040 RY)
= [(4.3×10^4) + (2.3×10^4)] man-rem
= 6.6×10^4 man-rem

Assuming 19,900 man-rem is required for accident cleanup and using the above estimated accident frequency reduction, the estimated ORE reduction would be about 500 man-rem.

For backfit plants, implementation would mean replacement of valves and pumps designated as inadequate through resolution of the study portion of this issue. For forward-fit plants, implementation is essentially eliminated because replacement valves are introduced during design and construction phases. It was assumed that 20 valves and 10 pumps per plant might be redesigned and replaced and that the replacement work would require 40 man-hours/valve and 80 man-hours/pump in areas averaging 0.05R/hr. For the 123 backfit plants, this would total about 9,800 man-rem of exposure. Since the redesigned valves and pumps would have lower failure rates, the time interval between repairs or replacement of this equipment due to subsequent failure would increase over the remaining plant life. This effect would reduce the accumulated labor as well as the occupational dose for subsequent repair or replacement of this equipment. This ORE reduction has not been quantified in this analysis because of the large uncertainty in identifying the types of valves and pumps to be replaced and each type of valve or pump may have different failure rates. This effect, however, would partially offset the estimated 9,800 man-rem for initial equipment replacement indicated above.

Cost Estimate

Industry Cost: Assume that each plant requires 2 man-years (88 man-wks) of engineering for pump/valve evaluation and replacement planning plus the equipment replacement labor assumed above. At \$2,000/man-wk, the labor cost is estimated to be:

$$[88 \text{ man-wk} + (20 \text{ valves}) \left(\frac{1 \text{ man-wk}}{\text{valve}}\right) + (10 \text{ pumps}) \left(2 \frac{\text{man-wk}}{\text{pump}}\right)] (\$2{,}000/\text{man-wk})$$
$$= \$256{,}000/\text{plant}$$

Further, assuming an average valve cost of \$30,000 and an average pump cost of \$500,000, the cost of replacement equipment per plant (20 valves and 10 pumps) would be \$5.6M. The estimated implementation costs for the 123 backfit plants are \$720M. However, this \$720M implementation cost would be partially offset by the savings in labor costs over the remaining plant life associated with the subsequent repair or replacement of the redesigned equipment as discussed above.

NRC Cost: Assume NRC will expend 3 man-years at \$100,000/man-year plus \$2M in technical assistance funds to generically assess pump and valve failures related to design and fabrication deficiencies and relate them to accident sequences to recommend equipment which warrants redesign and replacement. Also, assume 4 man-weeks per backfit plant to monitor replacement activities at \$2,000/man-wk. The NRC costs are estimated to be \$3M.

Value/Impact Assessment

Based on a risk reduction of 6.6×10^4 man-rem, the value/impact score is given by:

$$S = \frac{6.6 \times 10^4 \text{ man-rem}}{\$(720 + 3)M}$$

$$= 93 \text{ man-rem/\$M}$$

Other Considerations

An additional consideration is that plant damage is estimated to be $1.65 Billion per plant for a core-melt. Using the estimated accident frequency reduction, the averted plant damage could be as follows:

PWR: ($1,650M) ($1 \times 10^{-5}$/RY) (2,270 RY) = $37M
BWR: ($1,650M) ($4 \times 10^{-6}$/RY) (1,040 RY) = $7M.

Uncertainties

The assumption that valve and pump failure rates due to design and fabrication causes can be reduced 25% is highly judgmental. Less improvement in failure rates would directly decrease accident frequency reduction.

Taking longer than the 5 years assumed to install improved valves and pumps would decrease public risk reduction and increase the number of backfit plants, thus raising industry replacement costs.

If more than 20 valves and 10 pumps have to be replaced to achieve the estimated public risk reduction, the equipment replacement costs and occupational exposure would increase accordingly. Conversely, if less than 20 valve or 10 pump replacements can achieve the same estimated public risk reduction, the costs and ORE would decrease.

There is a potential saving in labor costs and ORE associated with repair or replacement of improved design valves and pumps subsequent to their installation. This saving is presently an uncertainty that could be estimated after the types and number of valves and pumps to be initially replaced are identified.

As stated above, about 10% of all plant outage time can be attributed to the malfunction of critical pumps and valves. There is a potential cost saving due to reduced outage time as a result of reduced equipment failure rates. However, as estimated above, reducing failures attributable to design and fabrication by 25% would reduce overall valve and pump failure probability by about 10%. Also, there is very little firm data showing how much forced plant outage is directly attributable to design and fabrication failure of valves and pumps in safety systems compared to systems necessary for normal power operation. Identification of the valves and pumps which warrant replacement would permit a reasonable estimate of this saving to be made. The 9,800 man-rem ORE estimated to initially install the improved design valves and pumps partially offsets the estimated public risk reduction of 66,000 man-rem resulting in a net radiation exposure reduction of about 55,000 man-rem.

CONCLUSION

Based on the value/impact score, the potential for reducing net radiation exposure by about 55,000 man-rem, and the consideration of the other uncertainties described above, this issue received a medium priority ranking.

In pursuing a resolution to this issue, NRR recognized the existence of the Nuclear Plant Aging Research (NPAR) program that was being conducted by RES. Systematic studies under this program were to be performed to: (1) identify aging and service wear effects associated with mechanical components that could impair plant safety, and (2) identify techniques that will be effective in determining aging and service wear effects, prior to loss of safety function, so that proper maintenance and timely repair or replacement can be implemented. Although the NPAR program is intended to encompass many component types, it is envisioned to include various safety-related valve types and pump components. RES intends to evaluate LWR operating experience and identify aging trends. One of the specific benefits cited is improved reliability and availability.

NRR evaluated the NPAR program and concluded that it generally encompasses the scope of the programs inferred by Items B-58 and C-11. When this program is completed, it is expected that recommendations will be made by RES for maintenance, repair, or replacement according to component type. At that time, these recommendations will be grouped into manageable tasks and considered by NRR for possible changes to regulatory requirements. Thus, this issue was RESOLVED and no new requirements were established.[863]

REFERENCES

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

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.

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

102. NUREG/CR-0848, "Operating Experience with Valves in Light Water Reactor Nuclear Power Plants for the Period 1965-1978," U.S. Nuclear Regulatory Commission, 1979.

863. Memorandum for T. Speis from H. Denton, "Closeout of Generic Issues B-58 and C-11," July 9, 1985.

ISSUE 14: PWR PIPE CRACKS

DESCRIPTION

Historical Background

Cracking has occurred in PWR piping systems as a result of stress corrosion, vibratory and thermal fatigue, and dynamic loading. However, as of February 1981, no cracking had been experienced in the primary system piping of PWRs. All incidents of cracking had been detected and corrective actions were taken prior to any catastrophic failures. This issue was identified as a potential USI in Appendix B to NUREG-0705[44] and addresses cracking of high pressure piping in PWRs. The issue of stress corrosion cracking of low pressure piping in PWRs is addressed separately in Item C-7.

This issue deals with ongoing occurrences of main feedwater line cracking in certain W and CE PWRs. In May 1979, the NRC was notified of cracking in two main feedwater lines at D.C. Cook, Unit 2. Subsequent volumetric examinations revealed crack indications at similar locations in all feedwater lines of both D.C. Cook, Units 1 and 2. Follow-up action by the NRC resulted in the issuance of IE Bulletin No. 79-13 [862] (including Revisions 1 and 2) requiring feedwater piping inspections at other W and CE PWRs. A total of 17 incidents of cracking were reported at the 35 plants examined and these incidents encompassed all main feedwater piping.

A PWR Pipe Crack Study Group was established by the NRC in 1979 and its charter included investigations of: (1) the causes and safety significance of pipe cracks in PWR safety-related systems, (2) the ability of current ISI and leak detection techniques to detect these cracks, and (3) recommendations for both upgrading the licensing process for plants in the operating license and CP stages and for implementation of new criteria on operating plants. In September 1980, the PWR Pipe Crack Study Group completed its investigation of the issue and published its findings in NUREG-0691.[13]

Safety Significance

Cracking in PWR nonprimary system piping could lead to a lessening of the system functional capability and possibly result in situations such as degraded core cooling. Cracking in PWR primary system piping has not been experienced and the mechanisms and environmental conditions necessary to initiate and propagate the cracking in this piping are not known to exist. Therefore, the risk associated with PWR pipe cracks is negligible for the primary system and low for the other piping systems.

Possible Solution

The staff recommended that licensees implement an augmented ISI program.[126]

CONCLUSION

Work performed by the staff resulted in the evaluation of two proposed courses of action: (1) augumented inspection (short-term), and (2) SRP inspection requirements (long-term). Both of these options were calculated to have very low public risk reduction and, therefore, low value/impact. As a result, this issue was RESOLVED and no new requirements were established.[865]

REFERENCES

13. NUREG-0691, "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, September 1980.

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

126. Memorandum for R. Vollmer from T. Murley, "Prioritization of New Requirements for PWR Feedwater Line Cracks - New Regulatory Requirements," March 10, 1981.

862. IE Bulletin No. 79-13, "Cracking in Feedwater System Piping," June 25, 1979.

865. Memorandum for T. Speis from H. Denton, "Resolution of Generic Issue 14, 'PWR Pipe Cracks,'" October 4, 1985.

ISSUE 30: POTENTIAL GENERATOR MISSILES - GENERATOR ROTOR RETAINING RINGS

DESCRIPTION

Historical Background

The April 13, 1979 incident at Sweden's Barseback-1 nuclear plant involving the failure of a generator rotor retaining ring was identified by AEOD in 1982 as a potential generic safety issue.[490] As a result of the AEOD concern,[799] NRR agreed to prioritize the issue.

Safety Significance

There have been 32 recorded events of failure of generator rotor retaining rings. The retaining rings restrain the radial forces generated by rotor coil ends, insulation, and packing blocks. For an 1100 MWe plant, the generator rotors may be up to 6 feet in diameter and 7 feet long and may weigh approximately 4,000 pounds. In 6 recorded cases, the failure of these retaining rings resulted in major damage to the generator and, in 2 cases, to the plant structure. The pieces of the broken retaining rings are expelled axially as compared to the turbine missiles (see Item A-37) which are expelled tangentially. The failures have been principally experienced on the exciter end of the generator, the end away from the turbine. Of concern is the potential of these large missiles to do damage to the plant. Further details of retaining ring failure can be found in EPRI EL-3209.[819] All plants are affected by this issue.

Possible Solution

Since current requirements for turbine and generator orientation are to preclude damage from turbine missiles, the positioning may not be optimum to protect against missiles resulting from failed rotating rings. In such cases, the only solution may be the erection of shields to restrain these missiles. In addition, most of the failures have resulted from stress corrosion cracking induced principally by water. A higher frequency of inspections for crack presence plus added precautions to assure a dry environment would reduce the probability of crack initiation and growth leading to catastrophic failure.

PRIORITY DETERMINATION

Assumptions

The same assumptions used in the turbine missile evaluations in Item A-37 will be used for this issue. These are: (1) the probability that a missile penetrates a barrier is 1, and (2) the probability of radioactive release given damage to safety-related equipment is 1.

Frequency Estimate

An estimate of retaining ring failure likelihood is 10^{-3} per retaining ring.[819] For the 32 recorded events of retaining ring failure, 6 led to extensive damage for a failure rate of 0.2 extensive damage occurrences per retaining ring. Six extensive damage events per ring failure are greater than the number of events resulting in missile ejection, since extensive damage events included events in which only the generator received extensive damage. However, due to the uncertainty involved in these infrequent events, 6 events are used in these calculations. There are 2 retaining rings per plant (generator). Assuming an average plant life of 40 years, the frequency of expected extensive damage events is given by:

$$\frac{(10^{-3}\text{ failure/ring})(0.2\text{ extensive events/failure})(2\text{ rings/plant})}{40\text{ years}}$$

$$= 10^{-5}\text{ extensive damage events/plant-year}$$

The probability of a safety-related target being struck by a missile is estimated to be 0.01. This value is based upon previous staff efforts related to turbine missiles where it was found that the prediction for low trajectory missiles for unfavorably-oriented generators generally fall within the range of 10^{-2} to 10^{-3}.[820,821] Thus, the frequency of an extensive event occurring and damaging some safety-related equipment is 10^{-7}/RY.

Consequence Estimate

As in the case of turbine missiles (Item A-37), a realistic estimate of a radioactive release to the environment is a gap release and not a core-melt. The consequences of the most likely release would be 75,000 man-rem per occurrence for the 90 PWRs and 40 man-rem for the 44 BWRs, based on the radioactive release categories described in WASH-1400.[16] The computer program CRAC2 applied to a typical Midwest site meteorology (Braidwood) was used for the dose calculation.[64] An average population density of 340 persons per square mile was used over an area which extended from an exclusion zone of one-half mile about the reactor out to a 50-mile radius about the reactor. This results in a public risk exposure of 19.1 man-rem for the PWRs and 5×10^{-5} man-rem for the BWRs, a total of less than 20 man-rem for all reactors. The change in transient-induced accident frequency created by generator ring missiles was calculated. However, the low initiating event frequency of 10^{-5}/RY (as compared to transient initiators which are greater than 1/RY) does not result in a significant change in risk.

Cost Estimate

Industry Cost: Assuming that shields would be required on 10 plants at $1M/plant results in total utility costs of $10M.

NRC Cost: It is estimated that NRC costs are $100,000 to evaluate this issue better.

Thus, the total cost associated with the solution to this issue is $10.1M.

Value/Impact Assessment

Based on a public risk reduction of approximately 19 man-rem, the value/impact score is given by:

$$S = \frac{19 \text{ man-rem}}{\$10.1M}$$

$$\cong 2 \text{ man-rem/\$M}$$

CONCLUSION

This issue should be DROPPED from further consideration.

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.

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

490. Memorandum for H. Denton from C. Michelson, "Potential Generator Missiles - Generator Rotor Retaining Rings," March 16, 1982.

799. Memorandum for C. Michelson from H. Denton, "Comments on AEOD Memorandum: Potential Generator Missiles - Generator Rotor Retaining Rings," April 14, 1982.

819. EPRI EL-3209, "Workshop Proceedings: Retaining Rings for Electric Generators," Electric Power Research Institute, August 1983.

820. Memorandum for R. Fraley from R. Vollmer, "Proposed NRR Revisions to Review Procedures for Turbine Missile Issue," May 12, 1983.

821. Memorandum for W. Johnston from T. Novak, "Midland SSER #3 - Turbine Missile Review," November 1, 1983.

ISSUE 55. FAILURE OF CLASS 1E SAFETY-RELATED SWITCHGEAR CIRCUIT BREAKERS TO CLOSE ON DEMAND

DESCRIPTION

Historical Background

In August 1982, AEOD reviewed a number of LERs related to Class 1E safety-related switchgear circuit breakers and found a high incidence of their failure to close on demand. A preliminary report was written and transmitted to NRR with recommendations for improvements.[281] NRR reviewed the AEOD report and did not agree with the AEOD conclusion.[282] The preliminary AEOD report was later finalized, issued as a reactor case study (AEOD/C301),[864] and transmitted to NRR.[661] A further NRR review of AEOD/C301[864] showed that NRR agreed with only one of the four AEOD recommendations. However, because of the AEOD concerns, NRR agreed to prioritize the issue.[662]

As a result of the AEOD concerns, IE Information Notice No. 83-50[663] was issued to licensees in August 1983. Comments, on AEOD/C301[864] were also provided by Region III.[664]

Safety Significance

The majority of safety systems contain large electrical components such as motors for pumps. Electrical circuit breakers must be closed to feed the power to these components. In addition, for cases of loss of offsite power, the diesel-generators must be connected (via breaker) to power all the plant electrical equipment. All of these breakers are normally closed by remote automatic electrical signals; however, they. can be closed manually by an operator at the switchgear, provided the circuit breaker closing circuit, control power, and breaker operating mechanism are free of defects. Failure to close the required breakers could lead to core-melt. This issue applies to the design and operation of all nuclear power plants.

Possible Solutions

The possible solutions to this issue are considered to be the four recommendations[281] made by AEOD and subsequently reviewed[282] by NRR:

(1) Provide for monitoring the status of the closing circuit of Class 1E safety-related switchgear circuit breakers and, for appropriately selected breakers such as diesel-generator output breakers, make the status indication available to the control room operator. Further, other selected breakers which are normally open and through which emergency equipment is powered should be reviewed to determine if such monitoring may also be warranted.

(2) In the short-term, licensees of operating reactors should establish regular local surveillance of Class 1E switchgear circuit breakers to monitor the readiness status of the spring-charging motor of each unit.

(3) In addition to the above, measures that tend to preclude dirty or corroded contacts, poor electrical connections, blown control circuit fuses, and improper return of breakers to operable status should be incorporated into the maintenance procedures and used in actual maintenance practice.

(4) Shift operating personnel should receive periodic training in the logic and operation of circuit breakers equipped with anti-pumping controls.

PRIORITY DETERMINATION

Assumptions

In an evaluation of the issue by PNL,[64] implementation of AEOD Recommendations 2 and 3 was assumed. Only the diesel-generator breakers were considered in the analysis because it was felt that they were the most significant contributors, based on their ability to simultaneously affect a large number of safety systems. The analysis was performed using ANO-1 as the representative plant.

Frequency Estimate

For ANO-1, only one dominant accident sequence corresponds to loss of emergency power--$T(LOP)LD_1YC$.[366] Of its minimal cut sets (dominant), only the following involve diesel-generator-related failures:

T(LOP) · LF-AC-DG1 · LF-AC-DG2 · LF-EFS-E11 · [0.36]
T(LOP) · LF-AC-DG1 · LF-AC-DG2 · LF-EFC D1D2CM · [0.05],

where the numbers in brackets [ ] represent the probabilities of nonrecovery within the estimated one-hour duration prior to onset of a core-melt.

The terms related to diesel-generator failure (LF-AC-DG1 and LF-AC-DG2) are redefined as follows to include a circuit breaker failure CBF:

LF-AC-DG1 = $(\text{LF AC DG1})_o$ + CBF1
LF-AC-DG2 = $(\text{LF-AC-DG2})_o$ + CBF2,

The terms with the subscript "o" represent the original terms and the designators "1" and "2" on CBF correspond to diesel generators "1" and "2", respectively. These term redefinitions result in the generation of two "new" minimal cut sets, representing the affected minimal cut sets for this issue:

T(LOP) · CBF1 · CBF2 · LF-EFS-E11 · [0.36]
T(LOP) · CBF1 · CBF2 · LF-EFC-DID2CM · [0.05]

The terms CBF1 and CBF1 were then calculated using the following approach. A fault tree for failure to energize Class 1E [safety-related electrical loads was constructed. This is caused by either diesel-generator failure or failure of the circuit breaker in its open position. The circuit breaker is failed open as a result of a failure in the breaker closing circuit and failure of the operator to order that the breaker be activated locally.

The latter is dominated by human error events. Failure to close the circuit breaker normally results from either an incorrect operator response or failure of the operator to respond to breaker position indicator lights. An incorrect operator response may occur if the operator responds to the wrong indicator light or his order to manually operate the breaker is misunderstood by another workman and the wrong breaker is closed. Failure of the operator to respond could be caused by improper indication of the breaker position or the operator failing to respond to correct light indications. Table 3.55-1 below lists the probabilities per demand for the basic events of this fault tree.

TABLE 3.55-1

Event	Probability	Information Source
(1) Operator responds to wrong light	$P(1) = 5 \times 10^{-3}$	NUREG/CR-1278[339]
(2) Workman throws wrong breaker	$P(2) = 5 \times 10^{-3}$	NUREG/CR-1278[339]
(3) Improper light indication	$P(3)$ = negligible[(a)]	WASH-1400[16]
(4) Operator fails to respond	$P(4) = 2.5 \times 10^{-1}$[(b)]	NUREG/CR-1278[339]

(a) Improper light indication requires two simultaneous demand-type failures of indicator lights i.e., green-light failure due to burn out and red-light indication due to spurious current. Probabilities for such failures are on the order of 1×10^{-6} and negligible compared to those for human error.

(b) From data for failure to respond to one of M lights on panel; value used corresponds to $M > 40$.

Failure of the operator on demand to effect on demand a manual bypass of the failed closing circuit is then equivalent to an unavailability given by.

$$A_{BF} = P(1) + P(2) + P(3) + P(4) = 2.6 \times 10^{-1}$$

The unavailability of the diesel-generator breaker closing circuit was estimated from the incidents reported in the AEOD preliminary report.[281]

Number of failure to close events = 94
Number of reactors affected = 42
Period considered = 5.25 years

Analysis of these data shows that the number of incidents varied from 0 to 3 per reactor-year and 1 to 8 per 5.25-year period for individual reactors. As these data were derived from required LERs, it is assumed that no such failures of the Class 1E circuit breakers were reported from any other operating reactor.

Assuming periodic inspection every W weeks and a 1-day repair time if a breaker closing circuit is found defective,

Average down-time (T) = (W/2 + 1/7) weeks.

$$\text{Failure frequency } (\lambda) = \frac{N_F}{(341)(52)} \text{ per week}$$

where N_F = number of failures
341 = the sum of reactor-years in reporting period
52 = the number of weeks/year

Unavailability of breaker closing circuit ($\bar{A}_{BCC}$) is given by:

$$\bar{A}_{BCC} = \lambda\ T$$

Unavailability of breaker to close on demand ($\bar{A}_{CBF}$) is given by:

$$\bar{A}_{CBF} = \bar{A}_{BCC} \cdot \bar{A}_{BF}$$

$$= 0.26\ \bar{A}_{BCC}$$

The unavailability of the breakers to close on demand is critical in the case that transfer of safety-related electrical loads to diesel-generator power is required. The AEOD report[864] noted that approximately 25% of the incidents reported involved a diesel-generator output breaker The failure frequency calculation therefore assumed $N_F = (94)(0.25) = 23.5$. Therefore,

$$\lambda = \frac{23.5}{(341)(52)} = 1.33 \times 10^{-3}\text{/week}$$

The following table summarizes $\bar{A}_{BCC}$ and $\bar{A}_{CBF}$ for three inspection frequencies:

Breaker Unavailability as a Function of Inspection Frequency

Inspection Frequency (W)	$\bar{A}_{BCC}$ $[(\lambda)(T)]$	$\bar{A}_{CBF}$ $[(0.26)\ (\bar{A}_{BCC})]$
4 weeks	2.9×10^{-3}	8.0×10^{-4}
2 weeks	1.5×10^{-3}	4.0×10^{-3}
1 week	8.6×10^{-4}	2.3×10^{-4}

NRC has no regulatory requirement for monthly inspections. However, assuming licensees' current inspection procedures require monthly inspections of the circuit breakers, the base case frequencies of the affected cut sets become 3×10^{-10}/RY and 4.8×10^{-11}/RY, respectively. Original values from the ANO-1 study are used for all terms except CBF1 and CBF2 (which are taken as 8.0×10^{-4} as shown before). Thus the base case affected core-melt frequency is 3.5×10^{-10}/RY for PWRs. Scaling this value for BWRs resulted in a base case affected core-melt frequency of 2.6×10^{-10}/RY.

Increasing the inspection frequency to once per week results in an adjusted case core-melt frequency of 2.8×10^{11}/RY (based on an adjusted case value of 2.3×10^{-4} for CBF1 and CBF2). Therefore, the reduction in core-melt frequency for PWRs and BWRs is 3.2×10^{-10}/RY and 2.4×10^{10}/RY, respectively.

Consequence Estimate

There are 90 PWRs and 44 BWRs with average remaining lives of 28.8 years and 27.4 years, respectively. Based on the reductions in core-melt frequency calculated above, PNL determined that the total public risk reduction associated with this issue is 2 man-rem.

Cost Estimate

Industry Cost: The costs to implement the recommendations were estimated by PNL.[64] Assuming 5.5 man-weeks/plant would be required to implement the recommendations in the plant procedures for operating plants, the total implementation cost was estimated to be \$1.17M. Future plants are not affected since the above plans can be incorporated in their initial procedures.

Based on an increase in labor of 2.5 man-weeks/RY for weekly inspections and/or maintenance of Class 1E diesel-generator circuit breakers, the total operation and maintenance cost is \$21.5M. This estimate includes training time. Thus, the total industry cost is approximately \$23M.

NRC Cost: The cost for development of the solution was calculated to be \$120,000, based on an estimate of 1.2 man-yrs. It was assumed that NRC review and approval of industry plans for implementing the solution would involve 1 man-week/plant for a total cost of \$160,000 for all plants. NRC labor to check utility compliance with the solution through inspection/verification was assumed to be 1 man-hr/RY. Thus, total operation and maintenance costs were estimated to be \$215,000. Therefore, the total NRC cost associated with the solution to this issue is approximately \$0.5M.

Value/Impact Assessment

Based on an estimated public risk reduction of 2 man-rem, the value/impact score is given by:

$$S = \frac{2 \text{ man-rem}}{\$23.5\text{M}}$$

$$\cong 9 \times 10^{-2} \text{ man-rem/\$M}$$

Other Considerations

(1) The low cost recommendations i.e., revising procedures, could be cost-beneficial on those plants that have experienced a relatively larger number of failures.

(2) The area of diesel-generator output breakers has also received attention during the staff's investigation of USI A-44, "Station Blackout." In NUREG/CR-2989,[665] it was concluded that the output breakers (in combination with load sequencers) were responsible for about 10% of all emergency AC power system failures. The Regulatory Guide which is to be issued along with the resolution of USI A-44 will address the area of diesel-generator output breakers as part of reliability improvements of onsite sources.

(3) The NRR responses[662] to AEOD concluded that the overall issue could be effectively addressed by improvements in maintenance procedures and periodic testing. IE Information Notice No. 83-50[663] was later issued by OIE.

(4) Implementation of the solution will not increase occupational dose because it involves the specification and authorization of inspection procedures. However occupational dose from operation and maintenance of the solution was estimated to increase by 750 man-rem.

CONCLUSION

In AEOD/C301,[864] a number of failures of circuit breakers were tabulated and then evaluated to determine recommendations to remedy the problems found. This report did not provide any evaluation of the potential safety significance of the failures and did not address the following question: Are such failures an indication of an unacceptable failure rate? Based on the above risk analysis, we have concluded that the potential safety significance does not appear to indicate a need for issuing generic requirements. Furthermore, the issue was adequately addressed by IE Information Notice No 83-50.[663] Based on the value/impact score calculated above, this issue should be DROPPED from further consideration.

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.

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281. Memorandum for H. Denton. et al., from C. Michelson, a "Case Study Report - Failure of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand," August 4, 1982.

282. Memorandum for C. Michelson from H. Denton. "AEOD Preliminary Report on Failures of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand," September 23, 1982.

339. NUREG/CR-1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," U.S Nuclear Regulatory Commission, February 1983.

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.

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664. Memorandum for D. Eisenhut from R. Spessard, "Unmonitored Failures of Class 1E Safety-Related Switchgear Circuit Breakers and Power Supplies (AITS-F03052383)," June 1, 1984.

665. NUREG/CR-2989, "Reliability of Emergency AC Power System at Nuclear Power Plants," U S. Nuclear Regulatory Commission, July 1983.

864. AEOD/C301, "Failures of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand," Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, April 1983.

ISSUE 61: SRV LINE BREAK INSIDE THE BWR WETWELL AIRSPACE OF MARK I AND II CONTAINMENTS

DESCRIPTION

Historical Background

The SRVs of a BWR plant provide protection against overpressurization of the reactor primary system. During normal operation, the SRVs which are mounted in the main steam lines open on high pressure permitting steam to escape from the reactor vessel. SRV discharge lines carry the steam through the drywell, into the wetwell, and discharge into the suppression pool thus condensing the steam. Failure to condense the steam would eventually lead to rupture of the containment boundary and possibly loss of reactor coolant inventory.

This issue postulates a break in the SRV discharge line in the wetwell airspace above the suppression pool of Mark I and II plants. Coupled with the line break is a failure of the relief valve to close after its actuation in response to the transient. The relief valve must be postulated to remain open for a significant amount of steam to escape, bypass the pool, and threaten overpressurization of the containment vessel with rupture in approximately ten minutes. This issue was identified as a potential generic safety issue at the April 29, 1982 meeting of the ACRS Subcommittee on Hydrodynamics and was formally proposed as a generic safety issue by GIB on August 20, 1982.

Safety Significance

The scenario described above would result in a direct release of reactor coolant and effluents to the environment. If major core damage or core-melt were to occur, either as a result of the above event or as an independent event, large off-site releases of radioactivity would be experienced.

Possible Solutions

The three possible solutions postulated are as follows:

1. Reduce the probability of containment failure* for the stuck open SRV with discharge line failure in the wetwell air space by the automation of the Containment Spray System (CSS).

2. Reduce the probability of containment failure* for the stuck open SRV with discharge line failure in the wetwell air space by increased inspection of the discharge lines in the wetwell air space.

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* For the purpose of analysis of this issue, overpressure failure of the BWR Mark I and II containments was assumed to result in a core-melt event through loss of the suppression pool. Containment failure for normal SRV discharges to the pool are not assumed as these loads provide only one component of the combined loads (SRV, LOCA, and Seismic) for which the containment (wetwell) is designed.

3. Reduce the probability of containment failure* for the stuck open SRV with discharge line failure in the wetwell air space by installation of guard pipes around the SRV discharge lines in the wetwell air space.

PRIORITY DETERMINATION

Technical analysis of the first prospective solution for this issue was performed by PNL and is documented in NUREG/CR-2800.[64] Elements of the PNL analysis were used by the NRC staff to include the other two prospective solutions.

The issue is a generic concern but is limited to BWR reactors using the Mark I or Mark II containments. Using the data base in Appendix C of NUREG/CR-2800,[64] the issue was assumed to be applicable to 24 plants with Mark I containments (22 operating and 2 yet to be licensed for full power) and 10 plants with Mark II containments (2 operating and 8 yet to be licensed for full power).

Frequency/Consequence Estimate

Solution 1 - Automate Containment Spray

The PNL analysis of the issue made use of a risk assessment performed by BNL.[295] The BNL risk assessment identified a series of new accident sequences which had not previously been considered in BWR risk assessments. The series of events were described as T·P·D·Z, T·P·D·(1-Z), and T·P·D·(1-Z)·W where:

T is the frequency of an anticipated transient with relief valve actuation. T = [illegible]/RY.

P is the probability that a relief valve sticks open.
P = (1.5n) (4.5×10^{-3})/Transient, where n = the number of valves actuated by the transient.

D is the probability of the failure of a relief valve discharge pipe when subjected to relief valve discharge flow.
D = (1/n)(7.4×10^{-5})/event.

Z is the probability that containment spray is not manually activated soon enough after the initiation of the transient (10 min.) to prevent containment overpressure failure.
Z = 5×10^{-1}/demand.

W is the probability that containment failure occurs even when containment spray is actuated within the 10 minute period following the initiation of the transient. W = 1.5×10^{-3}/demand.

Derivation of values for the probabilities of the individual events (T, P, D, Z, and W) is documented in the PNL risk assessment.[64]

Of the three new event sequences, BNL determined that the T·P·D·Z sequence is by far the dominant sequence. The PNL review affirms this conclusion. The base case probability of core-melt for the T·P·D·Z sequence was found to be 10^{-6}/RY, the probability of the T·P·D·(1-Z) sequence (a non-core-melt event) was also found to be 10^{-6}/RY, and the T·P·D·(1-Z)·W event (a core-melt event) was found to be 1.5 x 10^{-9}/RY. The T·P·D·Z and T·P·D·(1-Z)·W events are assumed to result in early containment failure and, as a result, BWR Category 2 or 3 releases would be expected. The T·P·D·(1-Z) event is expected to result in containment pressures in excess of design but not containment failure or core-melt and, as a result, a BWR Category 5 release (a dose consequence of about five orders or magnitude less than the above core-melt events). Therefore, the dominance of the T·P·D·Z sequence is established.

The consequences of the T·P·D·Z event are taken to correspond approximately to the WASH-1400[16] BWR release Categories 2 and 3 because the sequence is expected to result in both an early containment failure and early core-melt. Consequences for these release categories are expressed in man-rem. The total whole-body man-rem dose is obtained by using the CRAC Code[64] for the particular release category. The calculations assume a uniform population density of 340 people per square mile (which is average for U.S. domestic sites) and a typical (mid-west plain) meteorology. The results of the dose equivalence calculations are expressed in Table D.1 of NUREG/CR-2800.[64] The total integrated dose equivalents for BWR Release Categories 2 and 3 are found to be 7.1 x 10^6 and 5.1 x 10^6 man-rem, respectively. Using these dose consequences and the frequency of the T·P·D·Z event, a base case risk of 6.6 man-rem/RY was determined.

Separation of the CSS from the ECCS and automatic actuation of the CSS are assumed to reduce the probability of Z (containment failure) by two orders of magnitude (i.e., $Z^* = 5 \times 10^{-3}$/demand). This results in an adjusted case probability of core-melt for the T·P·D·Z sequence of 10^{-8}/RY and an adjusted case risk of 6.6 x 10^{-2} man-rem/RY.

Subtracting the adjusted case values from the base case values, a core-melt frequency reduction of 9.9 x 10^{-7}/RY and public risk reduction of 6.5 man-rem/RY are obtained for the resolution of this issue. Since the issue is assumed to affect 36 BWRs with Mark I or II containments and these affected plants have an average remaining life of 26.8 yrs, the total public risk reduction is 6,000 man-rem and the total yearly core-melt frequency reduction is 3.4 x 10^{-5}/RY.

Solution 2 - Inspect SRV Discharge Lines in Wetwell Air Space

For the purpose of these evaluations, it is assumed that the inspection of the SRV discharge lines in the wetwell airspace at a much increased frequency (at about 3-year intervals) will result in a risk reduction equivalent to that for Solution 1. This may be an overly optimistic assumption but, as shown later, is a sufficient assumption for the comparison of potential solutions.

Solution 3 - Guardpipes Installed Around SRV Discharge Lines in Wetwell Airspace

This solution was also assumed to result in a risk reduction equivalent to that of Solution 1.

Cost Estimate

Industry Cost: Industry costs were estimated for each solution separately.

Solution 1 - Automate Containment Spray

Implementation of the CSS modifications would require a new containment penetration for a suction line, pump and motor installation, routing pipe for suction and discharge lines and connection to the existing containment spray header, and installation of circuitry for its automatic actuation. Assurance of ECCS integrity is assumed to be best achieved through a separate suction line for the CSS.

Manpower for design, engineering analysis, scheduling, purchasing, planning and QA is estimated to be 285 man-weeks/plant. Labor for installation of the CSS modifications is estimated to be 108 man-weeks/plant for the 24 backfit plants. The 10 forward-fit plants are assumed to be able to achieve the same modifications for a lower labor expenditure, since the modifications can be scheduled into the original construction schedule and the labor expenditure for forward-fit plants is thus estimated to be 86 man-weeks/plant. This results in a total estimated industry cost of \$34.1M for the CSS modifications.

The additional CSS equipment and actuation circuitry is assumed to increase plant maintenance and surveillance manpower requirements by 1 man-week/year per plant. This is estimated to be an increase of \$2.1M for the industry over the lifetime of the affected plants.

It is assumed that the CSS modifications could be accomplished during a refueling outage for the backfit plants and accommodated within construction schedules for the foward-fit plants. Therefore, no replacement power costs are estimated.

The total industry cost is thus estimated to be \$36.2M.

Solution 2 - Inspect SRV Discharge Lines in Wetwell Airspace

It is assumed that an adequate reduction in the probability of SRV discharge line failure can be achieved by requiring an ISI using visual and/or radiographic techniques at a frequent interval. We have assumed that the lines would be inspected three times in every 10-year operating cycle.

Because of the physical location and the lack of permanent structures in the proximity of the SRV discharge lines in the BWR Mark I and II containment wetwells, we have assumed that a 2-man team would require one shift to erect portable scaffolding, perform the inspection, and remove the scaffolding for each discharge line.

The number of discharge lines varies from about 9 in some Mark I plants to about 18 in the Mark II plants. Using the above estimated manpower per SRV discharge line (16 man-hours), the average number of discharge lines for the Mark I and Mark II plants, the assumed inspection frequency, and the previously identified affected group of plants and their respective projected lifetimes, we estimate about 18,000 man-weeks of inspection to be required. In addition, we have assumed that for every hour of physical inspection time it is expected the licensees will be required to expend a like amount of time in support of the inspector. We have, therefore, estimated that this solution would require an additional 18,000 man-weeks of supportive services (planning, report writing, film reading, repairs, logistics, etc.) over the lifetime of the affected plants.

At a cost of $100,000/man-year, we estimate the licensees total cost of this solution to be $72M.

Solution 3 - Guardpipes Installed Around SRV Discharge Lines in Wetwell Airspace

The installation of guardpipes around SRV discharge lines in the BWR wetwell airspace has been done at some European installations. The task is complicated by restricted access (in the Mark I containment especially) and the necessity to provide adequate support for the impingment loads and pool swell loads. In operating plants, the job is further complicated by the fact that the work must be performed in a low level radiation environment.

We believe that the complete installation of guardpipes in the hostile environment will require at least 3 months. Therefore, we believe that it would be extremely optimistic to assume that this solution could be pursued without an interruption of plant power generation. We estimated that it would require 1 month of replacement power at each of the 24 operating plants for a total cost of $216M for replacement power only.

Because the replacement power costs are envisioned to be so large, we did not perform a more detailed estimate of total licensee costs for this solution. However, we feel confident that total licensee costs for this solution would exceed $250M.

NRC Cost: For all three solutions, it was estimated that 1 man-year ($100,000) would be required to complete resolution of the issue, review and approve new requirements, and issue implementation orders. One man-week/plant was assumed for the review of licensees' plant modifications and/or operational changes. In addition, 0.1 man-week/RY was estimated for long term inspection of the licensee surveillance activities associated with the plant modifications and/or operational changes. This results in an estimated cost of $300,000 for the above review and inspection activities. The total NRC cost for resolution of the issue is thus estimated to be $400,000.

Value/Impact Assessment

Assuming that all 3 solutions will result in the same public risk reduction (6,300 man-rem), Solution 1 appears to be the most effective solution. It is the least costly and is expected to result in the least ORE. The value/impact score for Solution 1 is given by:

$$S = \frac{6{,}300 \text{ man-rem}}{\$(36.2 + 0.4)\text{M}}$$

$$= 164 \text{ man-rem/\$M}$$

Other Considerations

All 3 potential solutions to this issue will entail entries to the containment wetwell and activities in a low level radiation field. In Solution 1, only a portion of the expended manpower would be performed in the radiation field. In Solution 3, almost all of the physical manpower would be expended in the radiation environment. In Solution 2, all the inspection effort would be in the radiation environment.

We have assumed that all efforts performed in the containment wetwell and the ECCS pump room are performed in a 15 millirem/hr field. Using the previous labor manpower estimates, we have estimated an ORE of 2,100 man-rem for Solution 1 (automatic CSS) and 11,000 man-rem for Solution 2. Solution 3 (guard-pipes) would be expected to have a greater ORE than Solution 1.

Issue 85 focused on failures of the VB valves attached to steam lines which discharge to the pressure suppression pool in BWR containment buildings. During the course of the analysis of Issue 85, it was determined that the failure of a VB valve on an SRV discharge line in the closed or near-closed position poses a potential for increased hydrodynamic loads on the SRV discharge line and the containment wetwell and, as such, the risk associated with that scenario should be considered in this issue (Issue 61). Likewise, the closed failure mode of VB valves on the HPCI and RCIC turbine exhaust lines poses a similar threat to the containment wetwell integrity and must also be considered in this generic issue. Failure of the HPCI or RCIC turbine exhaust line VB valves in the open position could result in bypass of the suppression pool and overpressurization of the wetwell and thus also must be considered in the analysis of this issue.

The analysis of the SRV discharge line and HPCI/RCIC turbine exhaust line VB valve failure is described as follows:

<u>SRV Discharge Line VB Valve</u>: Failure of the SRV discharge line VB valve in the open position is considered in Issue 85. Our review of the Grand Gulf dominant risk sequences found that none of the identified sequences were appropriate for the case in which the VB fails such that the valve disc is fixed in the closed or near-closed position. Failure of the VB in the closed or near-closed position, when combined with a second actuation of its SRV ("second pop"), could result in increased hydrodynamic loads. If the increased hydrodynamic loads are severe enough, the following failures could occur: (1) failure of the wetwell structure, (2) failure of the SRV discharge line, or (3) failure of the SRV.

We developed new sequences which are appropriate for the failure of the VB in the closed or near-closed position and subsequent events. The initiating events are common to all the sequences and are defined and assigned the indicated probabilities as follows:

(T_1)	= frequency of a transient initiated by loss of power	= 0.2/RY
(T_{23})	= frequency of all other transients resulting in reactor shutdown	= 7.0/RY
$(SRV)_1$	= probability of SRV actuation for a T_1 transient	= 1.0/event
$(SRV)_{23}$	= probability of SRV actuation for a T_{23} transient	= 0.8/event

$(SRV\text{-}2)_1$ = probability that an SRV, once actuated in response to a T_1 transient, will undergo a second opening = 1.0/event

$(SRV\text{-}2)_{23}$ = probability that an SRV, once actuated in response to a T_{23} transient, will undergo a second opening = 0.8/event

(X) = probability of VB valve failure = 0.0093/demand

(Y) = probability that, given a VB valve failure, the disc remains in a static closed or near-closed position = 0.01/VB failure

Bases for the values assigned to the above specific events are explained below. The frequencies for the T_1 and T_{23} events were taken from the Grand Gulf PRA. Since loss of offsite power will result in closing of the MSIVs, it was assumed that, for the T_1 transient, the probability of both the initial opening of an SRV, $(SRV)_1$, and a subsequent second opening of the SRV, $(SRV\text{-}2)_1$, would be 1/event. For the T_{23} transient, a probability of SRV actuation $(SRV)_{23}$ and second SRV actuation $(SRV\text{-}2)_{23}$ of 0.8/event was assumed because most BWRs can accommodate a trip from about 50% power with adequate heat rejection through the turbine bypass and many trips occur during start-up or at low power. The probability of VB valve failure (X) was derived by PNL[64] from LER data. The probability of a VB failure occurring such that the disc is firmly stuck in the closed or near-closed position was assumed to be 0.01/event because, although it is theoretically possible for this failure to occur, it is not the expected failure and no instance of this type of failure has been observed.

For the scenario in which wetwell failure is postulated, the sequence of events leading to severe core damage is given by:

$$fem = [(T_1)\cdot(SRV)\cdot(SRV\text{-}2)_1+(T_{23})\cdot(SRV)_{23}\cdot(SRV\text{-}2)_{23}\cdot(SRV\text{-}2)_{23}]\cdot(X)\cdot(Y)\cdot(FCON)\cdot(CM)$$

In this scenario, (FCON) and (CM) are defined and assigned the indicated probabilities as follows:

(FCON) = probability that the wetwell fails due to increased hydrodynamic loads = 10^{-4} to 10^{-5}/demand

(CM) = probability that transient escalates into a severe core damage event because of wetwell failure = 0.1/event

FCON was assumed to be in the range of 10^{-4} to 10^{-5}/demand after considerable discussions with CSB, GIB, MEB, and SGEB which revealed that: (1) results from tests of the Monticello and Caorso (Italy) SRV discharge lines, when extrapolated through engineering judgment, would indicate a maximum hydrodynamic load on the wetwell of less than twice the load used for design of the wetwell, and (2) when this increased hydrodynamic load is considered in a mechanistic combination of applicable loads (as opposed to the non-mechanistic load combination used for design), failure of the containment wetwell would not be expected. The probability of severe core damage (CM) caused by containment wetwell failure (i.e., loss of recirculation water inventory) is the same value that was calculated previously. This value was obtained by adjusting the probability of core-melt derived for a PWR with loss of recirculation coolant (0.25/demand) to account for the significantly greater volume of water available for injection from the Condensate Storage System in the BWR design, as well as the availability of more "avenues" for getting that water to the reactor. Using the above accident sequence and the indicated event probabilities results in a calculated core-melt probability of 4.35×10^{-9}/RY. Since the failure of the wetwell due to hydrodynamic loading would occur early in the transient, it was assumed that the consequences of this event would be best approximated by the BWR Category 2 Release Category (i.e., 7.1×10^{-6} man-rem/event). When applied to the population of 44 BWRs with an average remaining life time of 27.4 years, a total potential public risk of 37.2 man-rem was calculated for this scenario.

The second scenario (failure of an SRV VB valve in the closed or near-closed position when combined with a second SRV opening, "2nd POP") causes an increased dynamic load on that SRV discharge line. The analysis of this scenario, using the previously identified common initiating events and the containment failure and core-melt probabilities, indicates a total estimated public risk potential of 144 man-rem. Since this scenario represents just another "avenue" for SRV discharge line failure in the wetwell air space, the public risk potential was calculated previously.

The failure of an SRV VB valve in the closed or near-closed position when combined with a "2nd POP" of its SRV might also result in damage to the SRV (scenario three) because of increased dynamic loads or water hammer in the SRV discharge piping. This might cause the SRV to either not open under its next opening demand or fail in the open or leaking position. We have not attempted to evaluate the fail-to-open-on-demand event because of the extensive degree of redundancy in the design of the BWR SRVs and safety valves and the fact that failure of an SRV to open is a DBA. (PRAs for BWRs have consistently shown that DBAs are not a significant contributor to public risk.) For the case of induced failure of the SRV in the open position, examination of the Grand Gulf PRA reveals that the probability of SRV failure in the open or leaking position (P) used in all PRA scenarios is 0.1/demand. To include the effects of VB failure in the closed position in those scenarios resulting in an SRV failure in the open or leaking position, one would add the probability of that event to the 0.1/demand assumed in the PRA and recalculate the risk involved with all accident sequences in which P is one of the events in the sequence. We have calculated the additional probability of the SRV open or leaking failure due to VB failure in the closed position and SRV "2nd POP," using the conservative assumption that this event will always result in an SRV open (or leaking) failure. We calculated this additional probability of P to be 1.5×10^{-4}/demand. This is insignificant compared to the 0.1/demand assumed in the Grand Gulf PRA calculations and can therefore be neglected.

It should be noted that two design features of some BWR plants were not factored into the above calculations, and that consideration of these features would result in a reduction of the calculated potential core-melt frequency and public risk. Specifically, these design features are parallel VB valves and SRV low-low level reset logic. Nearly half of the BWRs have two VB valves per SRV discharge line in a parallel flow path arrangement (i.e., a redundant VB valve). For the plants with this design arrangement, the potential public risk associated with a VB valve failure would be one to two orders of magnitude less than we have calculated for the failed-closed VB event. Sixteen of the BWRs have adopted a low-low reactor coolant level SRV reset logic as a means of reducing the number of second SRV openings. If this factor were to be included in a more rigorous analysis, the public risk associated with the SRV VB valve failed-closed event would be reduced, but not by as large a factor as for the parallel VB valve design.

Adding the potential public risk estimates for the 3 failure scenarios associated with the SRV VB valve fail-closed (or near-closed) mode results in a total maximum potential public risk of about 180 man-rem.

Vacuum Breakers on Other Steam Lines: We found that only the HPCI and RCIC turbine discharge lines can additionally discharge steam to the wetwell pool and are equipped with VBs. Our review of the HPCI and RCIC system drawings from the OIE Training Center BWR Systems Manual and conversations with one of the Training Center BWR instructors indicate that the vacuum relief lines for both turbine exhausts are 2 in. lines and have multiple VBs and a motor-operated valve in series/parallel arrangements which are designed to provide redundacy for both the VB fail-closed and fail-open scenarios. However, the sensitivity to the fail-open (leaking VB) event is greatly heightened because the HPCI and RCIC turbine discharge line vacuum is relieved by the vacuum line to the wetwell air space instead of the drywell as is done with the SRV discharge lines.

We have analyzed VB failure events for these lines in the same manner as the analysis for the SRV line VBs, using the VB failure frequency determined by PNL.[64] As in the case of the SRV VBs, we found that, for the assumption of VB failure in the closed or near-closed positions, there were 3 possible severe core damage scenarios: (1) failure of the containment wetwell structure due to increased hydrodynamic loads, (2) failure of the HPCI or RCIC turbine exhaust line in the wetwell air space, or (3) induced failure of the HPCI or RCIC turbine system.

Considering the specific HPCI and RCIC turbine exhaust line and vacuum relief line configurations, we calculated the following public risk potential for each of the three scenarios: (1) 0.18 man-rem, (2) 24 man-rem, and (3) 1.6 man-rem. Thus, the public risk potential for the HPCI/RCIC VB fail-closed scenarios is about 26 man-rem, a relatively small value.

Such is not the case for the HPCI and RCIC VB fail-open scenario because the leakage would bypass the containment suppression pool resulting in pressurization of the wetwell airspace (similar to SRV and HPCI or RCIC turbine discharge line failures in the wetwell air space). Our analysis of this scenario indicates a potential public risk of 820 man-rem for this scenario. Since the end result of this scenario is severe core damage as a result of wetwell air space overpressurization, the potential public risk from this scenario is considered in this issue.

We regard the above calculated public risk associated with failures of the HPCI and RCIC turbine exhaust VBs to be a closer approximation to an upper bound estimate than to an average estimate which would normally be used in a prioritization analysis. Available LER data indicate that there has only been one confirmed HPCI or RCIC VB failure (a leakage failure). A more rigorous determination of the failure rate for HPCI/RCIC VBs would probably result in a calculated failure rate of one or two orders of magnitude less than that calculated by PNL[64] for SRV and HPCI/RCIC VBs from the combined failure data. However, the use of such failure data (one confirmed failure) would introduce large uncertainty in the estimate of HPCI/RCIC VB failure rate.

As calculated above, the maximum potential public risk associated with HPCI and RCIC turbine exhaust line VB failures is about 350 man-rem. Therefore, the total maximum public risk that can be attributed to the failure of SRV discharge line VB valves in the closed (or near-closed) position and the failure of HPCI and RCIC turbine exhaust line VBs is about 1,030 man-rem. If it is assumed that the resolution of this issue will result in an order of magnitude reduction in public risk from these VB failures, an additional maximum public risk reduction of about 930 man-rem can be allocated to the resolution of Issue 61. Factoring this into the priority score calculation and the total public risk reduction results in a revised priority score of about 190-man rem/$M and a revised potential public risk reduction of about 7,000 man-rem. Therefore, addition of the VB failure concerns will not alter the priority recommendation.

Staff efforts on the resolution of Issue 61 have been initiated. The approved Task Action Plan for the issue includes a sub-task devoted to the development of an accurate estimate of the failure rate of HPCI/RCIC turbine exhaust line VB valves. This is essential in determining whether improvement in HPCI and RCIC exhaust line VB valves is warranted, should a resolution for Issue 61 be adopted which does not result in automation of containment sprays.

CONCLUSION

The calculated value/impact score is indicative of a MEDIUM priority ranking. If ORE estimates are considered, it would tend to lower the priority of the issue.

REFERENCES

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

295. BNL-NUREG-31940, "Postulated SRV Line Break in the Wetwell Airspace of Mark I and Mark II Containments - A Risk Assessment," Brookhaven National Laboratory, October 1982.

ISSUE 85: RELIABILITY OF VACUUM BREAKERS CONNECTED TO STEAM DISCHARGE LINES INSIDE BWR CONTAINMENTS

DESCRIPTION

Historical Background

In BWRs, SRVs are mounted on the main steam line inside the drywell. Each SRV discharge is piped through its own discharge line (tailpipe) to a point below the minimum water level in the primary containment suppression pool. A vacuum breaker (VB) valve is installed on each discharge line to admit drywell air into the discharge line after SRV actuation and closure. This prevents a vacuum from forming due to the condensation of leftover steam in the discharge line. Water in the suppression pool then will not be drawn up into the line. The VB valve is similar to a swing check valve with a disk that swings on a hinge pin to open, and a spring to return the disc to a closed position.

VB valves are also mounted on other steam lines (the HPCI and RCIC turbine exhaust lines) that also discharge into the primary containment pressure suppression pool. However, the VB valves on these lines admit air from above the suppression pool (i.e., wetwell airspace) rather than drywell air.

Review of recent LERs has shown several instances in which VB valves from various vendors and in different plants have failed to properly operate, indicating a potential generic problem. Based on the information provided for this safety issue,[552] it appears that the cyclic impact of the disc on the VB valve seat due to steam discharge and condensing during SRV actuation or leakage presents a loading condition that has not been addressed in approved VB valve design and qualification requirements.

Safety Significance

Failure of a SRV discharge line vacuum breaker valve in the open position when combined with the failure of its SRV in the open position would result in an extended steam release to the drywell and would present the control room operators with a confusing set of indications, i.e. simultaneous indications of a stuck open or leaking SRV and a LOCA in the drywell. Several events have been reported in which the above scenario was evidenced. The most notable was the event at Hatch Unit 2 on August 25, 1982 which was evaluated in AEOD/C403.[795] Similar events that occurred at Browns Ferry Unit 1 and Peach Bottom Unit 2 provided the basis for the issuance of IE Information Notice No. 83-26.[789] The events at these 3 plants were also evaluated in AEOD/E322.[791] Misinterpretation and confusion on the control room operators part would be expected to increase the probability of operator error in the course of response to the event and might result in an increased likelihood of the event escalating into a severe core damage accident. Steam release to the drywell may also affect safety-related valves and instruments as well as increase the drywell temperature and pressure.

Failure of a SRV discharge line vacuum breaker valve in the closed or near closed position when combined with a second actuation of its SRV could result in hydrodynamic loads on the discharge line pipe and to the suppression chamber in excess of the design loads or could cause water hammer damage to the SRV. If the hydrodynamic loads are severe enough failure of the SRV discharge line or the suppression pool could occur with some probability that these failures would lead to a severe core damage event. Damage of the SRV could also lead to a greater frequency of challenges to the Reactor Protection system and the containment. Evaluation of the available LERs has not revealed a closed or near closed VB failure. Since a possible outcome of closed or near closed failure of a SRV VB valve would be to bypass the containment pressure suppression pool and/or loss of containment integrity, this failure mode is evaluated in Issue 61, "SRV Discharge Line Break in the BWR Wetwell Airspace of Mark I and II Containments."

Failure of HPCI or RCIC turbine exhaust line VBs in the closed or near-closed position when combined with multiple actuations of the turbine driven pump could also result in: (1) excessive hydrodynamic loads on the turbine exhaust line or the containment wet well structure, or (2) water hammer damage to the HPIC or RCIC Turbine System. Failure of HPCI or RCIC turbine exhaust line VBs in the open or leaking position could result in a suppression pool bypass leak to the wetwell air space and present the possibility of excessive containment pressurization. Since both the open and closed failure modes of the HPCI/RCIC turbine exhaust line VBs could result in bypass of the containment pressure suppression pool and/or loss of containment integrity, failure of HPCI and RCIC turbine exhaust line VBs is also evaluated in Issue 61. As a result, Issue 85 is limited to only the effects of SRV VB leakage failures.

Possible Solution

The reliability of VBs connected to SRV discharge lines inside BWR containment is assumed to be improved by development of NRC approved design criteria for VB valves, modification of current valve design(s) and a prototype qualification testing program(s). Licensees are assumed to replace the existing VB valves with a valve of the new qualified design. In addition, a Technical Specification is assumed that would require periodic operability testing of the VB valves.

All BWRs using VBs connected to SRV discharge lines inside containment would be affected by this issue. The resolution of this issue is applicable to all BWRs. Therefore, this issue applies to 44 BWRs with an average remaining lifetime of 27.4 years.

PRIORITY DETERMINATION

The prioritization of this issue is based in part on an analysis performed by PNL[64] and in part on an analysis by the NRC staff. Since the issue in question is generic and applies only to BWR plants, the Grand Gulf PRA was utilized as the basis for estimating the risk reduction which might be achieved by the assumed resolution of the issue.

Frequency/Consequence Estimate

For the case in which the SRV discharge line vacuum breaker valve is assumed to fail open (i.e., the valve will not reseat under SRV discharge flow or the disc is lost), significant pressurization and steam accumulation in the drywell will only occur for a prolonged SRV discharge. Thus, this effect will only be seen for those events for which the SRV does not properly reseat. Of the Grand Gulf dominant risk sequences, only the T.P.Q.I and T.P.Q.E sequences are affected by the failure of an SRV to reseat (i.e., event P). T is the frequency of a reactor transient (7.2/RY), P is the probability of SRV failure to reset (0.1/demand), Q is the probability of failure of the power conversion system (1/demand), I is the probability of failure of the residual heat removal system to remove decay heat from the suppression pool within 28 hours (8×10^{-5}/demand) and E is the probability of failure of emergency core cooling (1.2×10^{-5}/demand). Prolonged SRV release to the drywell through a failed open VB is assumed to result in a severe core damage event, through control room operator errors. Exposure of safety related instruments and equipment in the drywell was not considered because the environmental design loads for safety related equipment in the drywell exceed the expected environment following this event. Since containment failure due to H_2 Burn (γ) or steam explosion (α) is independent of the location of the SRV steam discharge to the containment, the T.P.Q.I.α and T.P.Q.E.γ sequences were eliminated as affected cut sets. This leaves only the T.P.Q.I.δ and T.P.Q.E.δ scenarios where δ represents the probability of long-term containment failure due to steam or non-condensable vapor overpressure. Examining these scenarios reveals that in the individual cutsets the only events requiring control room operator actions are the RECOVERY probability for the T.P.Q.I.δ sequence and the OP probability for the T.P.Q.E.δ sequence. In the Grand Gulf PRA, RECOVERY is defined as failure to restore maintenance/test faults or to take other corrective actions within 28 hours and is a sub-element of event I. Since confusion over whether a LOCA had occurred or whether a SRV and VB were stuck open or leaking is assumed to hamper only the initial diagnosis of the event and very early response actions, we assumed the probability of RECOVERY would be unchanged by an open failure of the VB; therefore, the T.P.Q.I.δ sequence was also eliminated as an affected dominant risk sequence.

In the T.P.Q.E.δ sequence, OP is defined as the failure of the operator to manually initiate the automatic depressurization system (ADS)and is a supplement of event E. Since the OP event is a short-term operator response, we assumed control room confusion resulting from failure of the VB in the open position combined with a stuck open SRV would increase the likelihood of the OP event by an order of magnitude from .0015 to .015/demand.

Analysis of the VB failure data, provided in the request for classification of this concern as a generic issue by PNL, resulted in a calculated VB failure rate (X) of 0.0093/demand. Since this issue involves a failed open VB in conjunction with a malfunctioning SRV and the other failures, the affected dominant sequence becomes T.P.X.Q.E.δ.

The Grand Gulf PRA did not assume VB failure in the development of the event trees resulting in severe core damage. Therefore, we calculated a modified base case frequency for the T.P.X.Q.E.δ scenario of 2.43×10^{-8}/RY. Assuming that resolution of the issue (i.e., improving VB reliability) will result in an order of magnitude reduction in the VB failure rate (i.e., $X^* = 0.00093$/demand), the post implementation frequency of the T.P.X*.Q.E.δ scenario is 2.43×10^{-9}/RY. Therefore, resolution of this issue would result in a reduction in the frequency of offsite release from a damage event of 2.18×10^{-8}/RY and a reduction in core-melt frequency of 4.36×10^{-8}/RY.

The T.P.Q.E.δ event results in a BWR Category 4 offsite consequence (6.1×10^5 man-rem/event). Multiplying the reduction in dominant risk event frequency

(2.18×10^{-8}/RY) by the Category 4 consequence (6.1×10^5 man-rem/event), the number of applicable plants (44), and their average remaining lifetime (27.4 years) results in a public risk reduction of 16 man-rem. This is the reduction in public risk and frequency of core-melt which might be provided by the improvement of SRV VB reliability for the fail open mode of VB failure. Assessment was utilized as the basis for estimating the risk reduction which might be achieved by the assumed resolution of the issue.

Cost Estimate

The solution to this generic issue is assumed to result in a generic program for the development of a staff approved design criteria for the SRV VB valves, modifications of the valve design and a qualification program. The existing valves would be replaced and a periodic operability test would be required.

Industry Cost: The estimated costs for industry implementation of the solution to this issue (i.e., replace the valves and test them periodically) was estimated by PNL, based on conversations with Browns Ferry staff involved in their recent testing and maintenance effort on the VB valves at their plant.

PNL has estimated the purchase of new VB valves and initial operability tests to total about $54,000/plant, for a cost of about $2.4M to the industry. We have added to that cost an additional $500,000 which we estimate the industry would be required to spend to fund a VB valve generic qualification program. This results in a total industry estimated cost for implementation of this issue of $2.9M.

The operability test requirement will require an estimated 0.5 man-day/plant year of industry effort over the remaining lifetime of the BWR plants, or a total testing cost of about $275,000. Thus, total industry cost is estimated to be $3.175M for resolution of this issue.

NRC Cost: It was assumed that cost for the development of design criteria and establishing an operability test for VBs would be sponsored by the NRC. It is assumed that a major portion of dynamic model development and engineering data is already available for use in establishing an adequate VB design criteria. The NRC effort was estimated to require 1 man-year for the development of the resolution of this issue for a cost of $100,000.

NRC review of the industry implementation of the resolution for the issue, i.e., selection and installation of a new VB valve and TS for the operability testing of the valve are assumed to require 1 man-week/plant of staff effort at a cost of $2,270/man-week or $100,000 total cost.

About 0.1 man-wk/RY is estimated for NRC review of periodic operability tests for VB valves. At $2,270/man-wk, this results in an estimated cost of about $275,000 over the remaining lifetime of the 44 BWR plants. The total NRC costs estimated for the resolution and implementation of the issue is thus calculated to be about $475,000.

Thus, the total cost for resolution and implementation of this issue is estimated to be $3.65M.

Value/Impact Assessment

Based on a total public risk reduction of 16 man-rem, the value/impact score is given by:

$$S = \frac{16 \text{ man-rem}}{\$3.65M}$$

$$= 4.4 \text{ man-rem/\$M}$$

Other Considerations

Replacement and operability testing of the SRV VB valves will require that the plant operators perform almost all of the work in the drywell in close proximity to the SRV valves. Using the same man hours estimated for valve replacement and testing for only the operating BWR plants and an assumed 35 millirem/hr field in the drywell, a total ORE of about 200 man-rem is estimated.

We assumed that in every instance in which an SRV leaks or fails to close and its associated VB valve leaks to the drywell, a plant shutdown is required and the source of drywell pressurization and temperature increase must be found and corrected. Using the previous estimates of the frequency of VB failure and SRV leakage, an estimated two-day shutdown for each VB failure and a replacement power cost of $300,000/day, we have estimated that over the lifetime of the 44 BWRs, these events will cost the industry about $40M in lost power production. When discounted to present worth, this is equivalent to about $20M to $25M.

When a SRV VB failure is detected, the valve is repaired or replaced. Resolution of this issue, i.e., placement of all existing SRV VBs with valves with an improved reliability, would therefore reduce the number of VB failures and accordingly reduce the number of VB replacements over the life of the BWRs. Using the estimated current failure rate, the frequency of challenges (transients) and an average number of SRV VBs per plant (9), we estimate about 725 expected SRV VB failures over the remaining lifetime of the BWRs. Improving the reliability of the VB by an order of magnitude would be expected to eliminate about 650 VB failures and, therefore, reduce the number of VB replacements by 650. Assuming 2 man-days of labor to replace a failed VB and a 35 millirem/hr work environment, we estimate that resolution of this issue would save about 350 man-rem of ORE.

The averted ORE due to reduction in core-melt frequency is estimated to be less than 1 man-rem. Therefore, when all components of ORE are considered, it appears that resolution of this issue would result in a net savings of about 150 man-rem of ORE.

CONCLUSION

The calculated potential public risk reduction and core-melt frequency reduction which might be obtained by the resolution and implementation of this issue are so small as to not justify further efforts on the issue. Therefore, we recommend that this issue be DROPPED from further consideration. However, it should be noted that, although from the risk-based regulatory perspective we recommend dropping the issue, there appears to be a large economic incentive to the industry to improve the reliability of SRV vacuum breaker valves.

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ISSUE 87: FAILURE OF HPCI STEAM LINE WITHOUT ISOLATION

DESCRIPTION

Historical Background

This issue concerns a postulated break in the HPCI steam supply line and the uncertainty regarding the operability of the HPCI steam supply line isolation valves under those conditions.[824] A similar situation can occur in the RWCU system.

The HPCI steam supply line has two containment isolation valves in series: one on the inside and one on the outside of the containment. Both are normally open in most plants; however, two plants operate with the HPCI outboard isolation valve normally closed. A HPCI supply valve, located adjacent to the turbine, and the turbine stop valve are normally closed. The RWCU also has two normally open containment isolation valves which must remain open if the system is to function.

The operation of the valves is tested periodically without steam. Due to flow limitations at the valve manufacturers' facilities, only the opening characteristics are tested under operating conditions. Therefore, the capability of the valves to close when exposed to the forces created by the flow resulting from a break downstream has not been demonstrated. However, there are reasons why the valves may operate under these accident conditions. The containment isolation valves are specified to open or close within 15 to 20 seconds. Calculations performed by Bechtel[826] indicate that the mass flow through the HPCI steam line isolation valves reduces from 1470 lbm/sec. at the time of the break to 328 lbm/sec. after 0.135 sec. and remains constant until the valve closes.

The valve type is not under the GE scope of control but is selected by the plant A/E. This results in a diversity of valves and valve types from plant to plant and increases the difficulty of demonstrating valve operating capability. Some plants have "Y-type" globe valves and others have gate valves.

One plant using globe valves for HPCI steam supply isolation has the valve inside containment positioned such that the steam flow exerts a force on the valve skirt in the close direction. This force is expected to reduce the closing torque requirement of the valve motor-operator and increase the probability that the valve will close when a large amount of steam is flowing through the valve. Also, some valve experts believe that the force required to open gate valves under pressure is greater than the force required to close the valve under flow.

Safety Significance

In Mark I containments, the HPCI steam line exits the drywell and enters the torus compartment where it typically traverses approximately a 75° arc before exiting to the HPCI pump room. In the four corners of the reactor building along the torus compartment are four triangular-shaped rooms which house the RHR/LPCI system, the RCIC system, and the core spray system. In some reactor buildings, there is a ventilation opening or a door, usually open, between the rooms housing the emergency core cooling pumps and the torus compartment. Given an unisolated break of the HPCI steam supply line in the torus compartment, the environment in the emergency core cooling pump rooms may exceed design limits. This places in jeopardy the other systems required to cool the core.

In Mark II containments, the emergency core cooling components are typically housed in individual rooms which are contained in the large annular-shaped area about the suppression pool. The HPCI steam supply line exits the containment and is then routed down through two floors to the room containing the HPCI turbine and pump. Again, given an unisolated break of the HPCI steam supply line, other systems which may be required to cool the core may be placed in jeopardy.

Possible Solutions

A proposed solution to the HPCI problem is to require that the outboard HPCI isolation valve be normally closed. However, a small bypass line on those plants not having this feature would be required to prevent thermal shock and water hammer and to provide assurance that leaks in the line would be detected before they become breaks. If the HPCI supply valve were kept normally open -- currently it is kept normally closed -- the probability of not getting steam to the HPCI turbine when needed might not be significantly changed.

Another solution that would apply to valves in any system might be a demonstration by test or the verification of use in other service applications that certifies the operability of the valve under line rupture flow conditions. If the normal HPCI steam flow rate approximates that estimated for a break in the steam line, the valves might be tested by individually closing them when the HPCI turbine is in operation.

PRIORITY DETERMINATION

Frequency Estimate

In the Browns Ferry IREP study,[760] the frequency for intermediate size steam line breaks (in which size category the HPCI steam supply line is included) is stated as being 2×10^{-4}/RY. It is also assumed that a break is equally probable at any point in the steam lines of this size category. The HPCI steam supply lines were estimated to constitute 23% of the steam lines in the intermediate size category. Hence, the frequency of a HPCI steam supply line break will be assumed to be 5×10^{-5}/RY.

The probability that both steam supply line isolation valves will fail to close is difficult to determine on a probabilistic basis. First, we are not dealing with random failures but rather with a lack of engineering knowledge. Second, if one valve fails to perform its intended function because of conditions which exceed its design capability, it would be most probable that the second valve would also fail to function. As an upper bound calculation, we can assume that the valve failure rate will be unity, given a line break, and that the dependency between valves is also unity. The lower bound can be calculated by assuming that the valve design is adequate and that there is no failure dependencies between the valves, so that the frequency of both valves failing is the product of the independent failure frequency of both valves.

The major contribution to the accident scenario being considered is the dependency between the unisolated steam line breaks and the low-pressure injection systems. For both the upper and lower bound calculations, it will be assumed that the dependence is unity, that is, that the low-pressure injection systems will fail, given an unisolated line break.

If, during the accident condition described, the core is maintained covered by the feedwater system, the steam mass flow generate by decay heat should lower to a point that would permit the closing of an isolation valve. One means available would be electrically closing the isolation valve inside the containment; the other means available is manually closing one of the isolation valves.

If the steam flow forces prevent the initial closure of the isolation valve, the motor control breakers will likely trip from the overcurrent condition before motor damage can occur. Further, the isolation valve inside containment will not have been exposed to the steam environment from the broken line. Resetting the motor control breaker would then permit energizing the valve motor and closing the isolation valve from the control room.

The second method available is to close one of the isolation valves by manual actuation of the hand crank. This would require suiting the operator in special garments and possibly using an airpack. Due to the expected high temperature in the torus compartment, the isolation valve inside the containment would be the valve most likely closed.

NEDO-24708A[827] analyzes an unisolatable 0.5 square-foot steam line break inside containment, which resembles a break of the 10 in.(0.55 ft^2) HPCI steam line from the time of the break up to the time that the low pressure systems would begin injection (225 seconds). The analysis also includes the water injected by the RCIC, but this should be minimal.

The 0.5 square-foot line break model predicts that the system pressure will fall below 300 psia at approximately 210 seconds after the break occurs. The water level will still be above the core and the condensate and the condensate booster pumps can be used (for those systems having a turbine-driven feed pump) to supply feedwater to the reactor. For those feedwater systems having motor-driven feed pumps, the feedwater system can supply feedwater continuously following the reactor trip.

With the feedwater system providing cooling water, the fuel will remain covered until a HPCI isolation valve is closed and the RHR system is restored to operation.

It is calculated that 12,500 gallons/hour of water at 94°F will be converted to steam at 212°F in absorbing the decay heat from the fuel. At this rate of consumption, a 500,000 gallon condensate tank could be emptied in 40 hours. In order to maintain adequate coolant for the extended time period, the vacuum must be restored in the condenser and the decay heat dissipated using the condenser. This will also necessitate using the auxiliary boiler to provide steam for the gland seals. Having the condensers available will reduce the steam pressure in the reactor thus reducing the amount of steam that will be discharged through the broken HPCI steam supply line and decreasing the consumption of water from the condensate storage tank. This action will also lower the amount of heat and humidity being dumped into the torus compartment.

The probability of the loss of the feedwater during a 168-hour interval, the time assumed necessary to restore the RHR system following a HPCI steam supply line break is calculated to be 0.03. This is based on the Browns Ferry IREP[760] frequency of transients that result in loss of feedwater (~1.4/RY). This equates to a mean time between failure of 5,570 hours. Assuming an exponential distribution, a failure rate of 1.8×10^{-4}/hour results.

Of concern is the operator actions needed to maintain the operation of the main feedwater system. Although this is an activity with which the operator should be very familiar, detecting that the HPCI is not providing make-up inventory may not be immediate. Further, the inventory in the hotwell must be maintained by flow from the condensate storage tank. To obtain an adequate flow, it may be necessary to reestablish the vacuum in the condensers. As reported in NUREG/CR-3933,[828] most recent PRAs assign a probability of 0.1 for failure to recover the power conversion system in a short interval. In this accident, the time needed to make the necessary operating adjustments will not be as short as required for transients or small breaks in liquid coolant lines. In addition, approximately one-fourth or one-half of the make-up water requirements will be provided by one or two-pump operation of the CRD hydraulic system. Thus, a human error probability of 0.05 will be assigned. The total probability of failing to maintain coolant inventory with the feedwater systems for 168 hours is (0.05 + 0.03) = 0.08. Thus, upper and lower bound estimates are:

$$(5 \times 10^{-5})(1)(1)(0.08) = 4 \times 10^{-6} \text{ core-melt/RY}$$
$$(5 \times 10^{-5})(10^{-3})(10^{-3})(1)(0.8) = 4 \times 10^{-12} \text{ core-melt/RY}$$

Closing the outboard isolation valve and opening the supply valve is assumed to result in no net change in the unavailability of the HPCI and, therefore, the frequency of other accident sequences is unchanged. Closing the outboard isolation valve until the HPCI is commanded does not reduce the accident rate from breaks that occur when the HPCI is energized or go undetected prior to the HPCI being energized. With the inclusion of a bypass line to prevent thermal shock, this contribution is believed to be much smaller than the long-term exposure with the line pressurized. Hence, the remaining contribution was not considered to be significant.

The BNL estimate[829] of the frequency of a core-melt accident due to an unisolated break outside the containment in a six-inch RWCU line was 1.4×10^{-5}/RY. The study also conservatively assumes that the conditional probability for the isolation valves failing to close given a line break is 1.

Consequence Estimate

A break in the HPCI steam supply line would be a LOCA outside containment. This would be closely equivalent to the PWR Event V sequence identified in WASH-1400.[16] The consequences are obtained using the CRAC Code.[64] We have assumed an average population of 340 persons per square mile (which is the average for U.S. domestic sites) from an exclusion area one-half mile about the reactor out to a 50-mile radius about the reactor. Typical midwest site meteorology is assumed. Based upon these assumptions, a release produces an exposure of 5×10^6 man-rem. With upper and lower bound frequencies of 4×10^{-6} and 4×10^{-12} core-melt/RY, the upper and lower values of risk exposure are then 20 man-rem/RY and 2×10^{-5} man-rem/RY, respectively. Based upon an average life of 24 years for each BWR having a HPCI system with open isolation valves which involves 24 reactors, the risk posed by this issue has an upper bound of 11,500 man-rem and a lower bound of 1.1×10^{-2} man-rem. The consequences of the RWCU line break sequence would be 70 man-rem/RY and 40,000 man-rem total.

Cost Estimate

Industry Cost: Industry cost estimates for implementation of the proposed change to leave the outboard isolation valve closed is estimated to be 2.5 man-years. This includes: an engineering review of the logic for HPCI initiation to assure that the valve will be commanded open and will properly isolate if required; preparation of changes to procedures (normal and emergency); revision to and operator training covering the change; revision to the FSAR; license amendment; and hardware changes. No added maintenance costs are anticipated. No hardware costs were assessed to add a bypass line because it is believed that most reactors already have this feature. At an average cost of $100,000/man-year, the total industry cost is $6.75M.

NRC Cost: The NRC cost is estimated to be 1 man-month/reactor or $210,000 for all reactors. However, there is at least one reported instance in which the isolation valve could not be opened under pressure. This occurrence was reported in AEOD/T420.[825] If these valves would have to be modified to open under pressure, the costs would be much greater.

Performing qualification tests on a selected sample of RWCU isolation valves and actuators and demonstrating, by analyses, that the other valves and actuator combinations will perform satisfactorily are estimated to cost $1M. If actuators have to be replaced, this would add to the costs.

Value/Impact Assessment

At the upper bound values of 11,500 and 40,000 man-rem, the value/impact score is given by:

$$S = \frac{51{,}500 \text{ man-rem}}{\$(6.75 + 0.21 + 1)\text{M}}$$

$$\cong 6{,}500 \text{ man-rem/\$M}$$

At the lower bound value of 1.4×10^{-3} man-rem, the value/impact score is given by:

$$S = \frac{1.4 \times 10^{-3} \text{ man-rem}}{\$(6.75 + 0.21)\text{M}}$$

$$\cong 2 \times 10^{-4} \text{ man-rem/\$M}$$

Other Considerations

Other considerations, which in individual cases may reduce the risk associated with this issue, include the absence of ventilation openings or open doors between the torus compartment and the pump rooms. The absence of these openings reduces the common cause failure potential of the RHR/LPCI, RCIC, and core spray systems with the HPCI steam supply line break. Consideration should be given to reducing the risk if the isolation valves were selected given the requirement to close under line break/steam mass flow conditions. This concern could be eliminated if it could be shown by test or from actual application that valve operation has been verified under loads equivalent to line break conditions.

A similar situation exists for the RCIC system. Since the RCIC steam line is smaller than the HPCI, the risk may not be as great, but would still add substantially to the values estimated previously.

CONCLUSION

At the upper bound value with both the RWCU and HPCI event sequences and the Event V consequences, this issue would be a HIGH priority item. Also the occurrence of the event results in the loss of one defense layer (containment). In addition, the costs to determine the capability of the valves to provide containment isolation are relatively small.

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ISSUE 91: MAIN CRANKSHAFT FAILURES IN TRANSAMERICA DELAVAL EMERGENCY DIESEL GENERATORS

DESCRIPTION

Historical Background

On August 12, 1983, one of the three emergency diesel generators (EDG) at the Shoreham Plant failed during overload testing as a result of a fractured crankshaft. The failure occurred in EDG-102 and similar crankshaft cracks were discovered in EDG-103 and EDG-101 on August 22 and 23, 1983, respectively. In addition to the crankshaft cracks, 4 of 24 connecting rod bearings were found to contain cracks in the bearing shells. All 3 EDGs were supplied by Transamerica Delaval, Inc. (TDI) and were Model DSR-48 diesels.

On August 30, 1983, IE Information Notice No. 83-58[780] was issued to inform licensees of the Shoreham event. Prior to this, IE Information Notice No. 83-51[781] had been issued to inform licensees of various diesel-generator problems. The staff reviewed the operating status of the 3 plants with TDI engines and sent letters to all TDI diesel owners requesting specific information about their respective engines. A letter was also sent to TDI on December 1, 1983 requesting information on the design development history of various parts of TDI machines. A response from TDI was sent on December 16, 1983 and, on December 23, 1983, the staff was informed that a TDI Diesel Generator Owners' Group had been formed to address the problem.

As a result of the EDG failure at Shoreham, a TDI Project Group was established by NRR on January 16, 1984.[782] On January 25, 1984, the staff provided the Commission with a status report in SECY-84-34.[783] In order to more clearly define the issue and to determine remedial action, the staff issued a letter to TDI on February 14, 1984 requesting more information.[784] In March 1984, the TDI Diesel Generators Owners' Group submitted to the NRC its program for addressing the issue.[785] In April 1984, the staff recommended to the Commission in SECY-84-155[786] that the question of reliability of TDI diesels had generic implications and should be reported to Congress as an abnormal occurrence. An SER on the TDI Diesel Generator Owners Group Program Plan (OGPP) was issued by the staff on August 13, 1984.[787]

In its SER, the staff's overall finding was that the OGPP incorporates the essential elements needed to resolve the outstanding concerns relating to the reliability of the TDI diesel generators for nuclear service, and to ensure that the TDI diesel engines comply with GDC 1 and GDC 17. These corrective actions include: (1) resolution of known generic problems (Phase I), (2) systematic DR/QR of all components important to reliability and operability of the engines (Phase II), (3) appropriate engine inspections and testing as identified by the results of Phases I and II, and (4) appropriate maintenance and surveillance programs as indicated by the results of Phases I and II.

After licensees complete Phases I and II of the OGPP, the licensing basis will be reviewed by the staff to determine what modifications to the license conditions will be required. A final SER will be issued for each of the plants that are being licensed or restarted on an interim basis. These are expected to include: Shoreham, Grand Gulf, San Onofre, Catawba, and Comanche Peak. For plants where Phases I and II are scheduled to be completed sufficiently ahead of licensing or restart, a final TDI Diesel SER will be developed that encompasses the results of Phases I and II and the operational history of an engine.

Safety Significance

In the event of loss of offsite power, the power to operate the equipment necessary to maintain core cooling is provided in most plants by EDGs. Although to varying degrees, plants can withstand the loss of both offsite and onsite AC power (and further requirements are being proposed in USI A-44), EDG unreliability is a significant contributor to the estimated frequency of core damage events. The question of diesel-generator reliability in general is addressed in Item B-56, "Diesel Reliability." Issue 91 applies to the design and operation of the 16 plants which have or have not ordered TDI diesel-generators.

Possible Solutions

The possible solutions to this issue are considered to be the three elements of the TDI OGPP:

(a) Phase I: Resolution of 16 identified generic problem areas intended (by the Owners' Group) to serve as a basis for the licensing of plants during the period prior to completion and implementation of the OGPP

(b) Phase II: A design review/quality revalidation of a larger set of important engine components to assure that their design and manufacture (including specifications, quality control, quality assurance, operational surveillance, and maintenance) are adequate.

(c) Identification of any needed additional engine testing or inspections based on findings from Phases I and II.

CONCLUSION

The solution to this issue has been identified in the staff's SER.[787] The need for changes to the SRP, STS, or Regulatory Guides will be addressed at the conclusion of Phases I and II of the TDI OGPP.

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786. SECY-84-155, "Section 208 Report to the Congress on Abnormal Occurrences for October - December 1983," April 11, 1984.

787. Letter to J. B. George (Transamerica Delaval, Inc. Owners' Group) from D. Eisenhut (NRC), "Safety Evaluation Report, Transamerica Delaval, Inc. Diesel Generator Owners' Group Program Plan," August 13, 1984.

ISSUE 94: ADDITIONAL LOW TEMPERATURE OVERPRESSURE PROTECTION FOR LIGHT WATER REACTORS

DESCRIPTION

Historical Background

Low temperature overpressurization (LTOP) was originally identified in NUREG-0371[2] as Item A-26. This issue later became USI A-26 and was resolved in September 1978 with a revision to SRP[11] Section 5.2. The resolution of USI A-26 affected all operating and future PWRs and required PWR licensees to implement procedures to reduce the potential for overpressure events and install equipment modifications to mitigate such events. MPA B-04 was established by DL to track the implementation of the resolution at operating PWRs.[578] Current staff requirements are in SRP[11] Section 5.2.2, "Overpressure Protection," and its attached BTP-RSB 5-2, "Overpressure Protection of Pressurized Water Reactors While Operating at Low Temperatures."

From 1979 to July 1983, 12 pressure transients were reported. Of these, 2 events at Turkey Point Unit 4 on November 28 and 29, 1981 exceeded the TS limit (415 psig below 355°F) by about 700 and 351 psi, respectively.[591,592] The overpressurization transients at Turkey Point were the first events to occur at an operating PWR that exceeded the TS limits since the NRC staff resolved USI A-26. The events were identified to Congress as Abnormal Occurrences which indicate that the events involved a major reduction in the degree of protection to the public health or safety.

The continuation of overpressure transient events and the two instances at Turkey Point may indicate potential weaknesses in the present overpressure protection criteria or its implementation that warrant further consideration. The two overpressure transient occurrences at Turkey Point resulted from one overpressure mitigation system (OMS) channel being out for maintenance and the other (redundant) channel being disabled by undetected errors during the first event and from undetected equipment malfunctions during the second event. These events were reported in AEOD/C401.[792]

Safety Significance

Major overpressurization of the RCS, if combined with a critical size crack, could result in a brittle failure of the reactor vessel. Failure of the reactor vessel could make it impossible to provide adequate coolant to the reactor and result in a major core damage or core-melt accident. This issue applies to the design and operation of all PWRs.

Possible Solution

Resolution of this generic issue was suggested by RSB,[788] MEB,[793] and AEOD[792,794] to include all or some of the following proposed new requirements:

(a) Amend the STS and the SRP to require each licensee to identify the criteria used to determine if and when the LTOP system setpoints need to be adjusted to account for the irradiation-induced embrittlement of the reactor vessel.

(b) Make more use of the relief valves in the RHR for LTOP by raising the setpoint for the auto-closure of the isolation valves.

(c) Amend the STS to allow no plant operation in the "water solid" condition with either train of the LTOP system out of service.

(d) Amend the STS to allow no plant to operate in the "water solid" condition with an SI pump in service.

(e) Require the LTOP system to be fully safety grade.

(f) Require all operating reactors to upgrade their TS to the STS for LTOPs.

PRIORITY DETERMINATION

Frequency/Consequence Estimate

Before 1979, there were 30 reported events in PWRs where the RCS pressure/temperature violated TS. After 1979, following changes to operating procedures and the implementation of OMS, there were 2 reported events of overpressure excursions at low temperature. Since 1979, PWRs have accumulated approximately 250 RY of operating time. Therefore, the currently expected frequency of overpressure excursion events is 0.01/RY. There was concern expressed for including 1979 experience since increased operator awareness of overpressure problems may have biased the results; however, the small number of installed OMS would have also permitted more overpressure events and it was concluded that the 1979 data should be included.

The reactor vessel and weld materials have toughness properties which are defined by the nil-ductility transition reference temperature, RT(ndt). The higher the copper and nickel content, the higher the RT(ndt). The RT(ndt) also increases with fluence or the cumulative exposure of the vessel to neutron irradiation. The probability of vessel failure due to a pressure spike is a function of the initial temperature (T) in relation to the RT(ndt) or the T-RT(ndt). It is also a function of the initial pressure and the change in pressure.

The probability of vessel failure was estimated using the Vessel Integrity Simulation Analysis (VISA) code[790] based on the assumed values of pressure, temperature, and RT(ndt). The code was a Monte Carlo technique which results in no probability of failure based on a reasonable number of runs if the expected flaw size distribution (which predicts small probabilities for a large 1/4 thickness flaw) is used. Therefore, to get an estimate, the probability of a 1/4 thickness flaw was assumed to be 1. The vessel failure probability calculated with this probability of a 1/4 thickness flaw was then reduced by a factor of 2250 to adjust the results to the expected flaw size distribution. This factor was obtained by ratioing the results given by two VISA runs: (1) assuming the expected flaw size distribution, but a very high copper and nickel content in order to force calculated failures, and (2) assuming the probability of a 1/4 thickness flaw to be 1 and the same very high copper and nickel contents. The adjusted estimate was then multiplied by 6 to account for the assumed 6 welds on the reactor vessel beltline.

Based upon a review of the previous overpressure events prior to 1978, it was found that 30% reached a peak pressure that was between 1,100 psia and 2485 psia. In another 5% of these events, the peak pressure was between 950 psia and 1200 psia. In the remaining 65%, pressure was prevented from exceeding 950 psia by operator actions. Thus, a series of VISA code runs were made at 2485 psia, 1200 psia, and 950 psia to obtain the probability of reactor vessel failure as a function of T-RT(ndt).

Two types of reactor vessels were analyzed. The first is represented by the Oconee 3 vessel with 0.20% copper and 0.63% nickel content. The second is represented by a vessel with high copper (0.35%) and nickel (1%) contents.

Based on the information available on 38 PWR reactors, the copper and nickel content of 14 of these reactors was higher than in the Oconee-3 vessel. Thus, 38% of the operating PWRs or 17 reactor vessels are assumed to be similar to the "High" plant and the remaining 30 vessels are assumed to be similar to Oconee-3.

At the midlife of the vessels, the fluence is estimated to be 8.5×10^{18} neutrons/cm^2. This fluence converts to a RT(ndt) of 267°F for the "High" vessel and 231°F for the Oconee-type vessel using the methodology contained in Rev. 2 to Regulatory Guide 1.99. If it is assumed that the starting temperature is 110°F and the T-RT(ndt) value is about -150°F for the "High" vessel and -120°F for the Oconee-type vessel. These values of T-RT(ndt) result in the probabilities of failure as follows:

	PROBABILITY OF FAILURE PER EVENT	
Peak Pressure (psia)	Oconee Vessel	"High" Vessel
2485	1.5×10^{-3}	2.2×10^{-3}
1200	7×10^{-7}	7×10^{-6}
950	$<1 \times 10^{-9}$	$<1 \times 10^{-9}$

The predicted probability of failure at 2485 psia peak surge at the end-of-life fluence (1.4×10^{19} neutrons/cm^2) for the Oconee vessel is 2.6×10^{-3} and 2.7×10^{-3} for the "High" type vessel. The average failure frequency for the Oconee-type vessels is calculated to be 4.5×10^{-6} failures/RY and 6.6×10^{-6} failures/RY for the "High" type vessel. It is assumed that a failure of the reactor vessel will result in a core-melt accident with a probability of 1. The implementation of the possible solutions would reduce the frequency of an LTOP occurring but not the probability of a vessel failure given the occurrence of an LTOP event. The frequency of LTOP events is expected to be reduced by a factor of 10 for the solutions proposed. This reduction in LTOP occurrence results in a core-melt frequency reduction of 4.05×10^{-6}/RY for the Oconee-type vessels and 5.9×10^{-6}/RY for the "High" vessels.

The core-melt accident resulting from a LTOP failure of the pressure vessel is expected to result in a S_1D accident sequence as defined in WASH-1400.[16]

The S_1D sequence is a small-break LOCA with failure of the emergency coolant injection. The S_1D sequence results in releases with the associated probability for the following release categories, given a core-melt.

PWR-1 = 0.01 PWR-5 = 0.0073
PWR-3 = 0.2 PWR-7 = 0.8

The whole body man-rem dose is obtained by using the CRAC Code[64] assuming an average population density of 340 persons per square mile (which is the mean for U.S. domestic sites) in an exclusion area from a one-half mile radius about the reactor out to a 50-mile radius about the reactor. A typical midwest meteorology is also assumed. Based upon these assumptions, the following whole body man-rem doses result from the following categories.

PWR-1 = 5.4×10^6 man-rem PWR-5 = 1.0×10^6 man-rem
PWR-3 = 5.4×10^6 man-rem PWR-1 = 2.3×10^3 man-rem

Utilizing the reduction in core-melt frequency, the probability per release category, and the whole body dose consequence factor, the public risk reduction was calculated to be as follows:

PUBLIC RISK (Man-Rem/RY)

Release Category	Oconee 3	"High"
PWR-1	0.2	0.3
PWR-3	4.4	6.4
PWR-5	0.03	0.04
PWR-7	0.007	0.01
TOTAL:	4.6	6.7

For the average remaining plant life of 26 years, the averted public risk is 120 man-rem/reactor and 174 man-rem/reactor for the Oconee 3 and "High" type of vessels, respectively. Based on a reactor vessel population of 47 (of which 17 are in the "High" vessel classification), the expected value of averted public risk is 6,560 man-rem.

Cost Estimate

Industry Cost: The industry costs are dominated by the costs associated with upgrading the OMS; principally, the PORVs to safety-grade. PNL estimated[64] that valve backfit labor costs are $27,200/plant based on 12 man-wks/plant and $2,270/man-wk. This includes management review, QA control, licensing review, and engineering for the backfit. Material requirements are 2 safety-grade PORVs and 2 instrumented (for automatic actuation) block valves, each costing $25,000. Incremental material costs such as piping, supports, hardware, etc., beyond those associated with initial installation of the safety-grade PORVs and instrumented block valves at a plant are estimated at $50,000. The cost for the safety analysis is estimated to be $50,000/plant. A Class III License Amendment for the valve upgrade is estimated to be $4,000. Therefore, the implementation cost is estimated to be $237,000/plant. Other industry costs for analysis, TS changes, and test procedure changes are expected to be $190,000/plant. Total industry costs are then $260,000/plant or $12M for all 47 plants. The operation/maintenance costs are not expected to significantly increase over the existing plant costs for operation and maintenance.

NRC Cost: The NRC costs are estimated to be $38,000 for development of a resolution and $10,000/plant for review of the overpressure mitigation provisions. The total NRC costs are expected to be $0.5M.

Value/Impact Assessment

Based on a public risk reduction of 6,560 man-rem, the value/impact score is given by:

$$S = \frac{6{,}560 \text{ man-rem}}{\$(12 + 0.5)M}$$

$$= 524 \text{ man-rem/\$M}$$

The upgrading of the OMS or LTOP system to safety grade (safety-related or important to safety) does not by itself assure improved system reliability. Hence, the benefit of making the OMS safety grade to assure a higher probability of successful mitigation of overpressure challenges may not be realized. A greater benefit may result from more stringent procedures and technical specifications, e.g., not permitting water solid operation without both channels of the OMS in operation. Thus, it may be possible to decrease the number of overpressure incidents and better assure OMS operation without hardware changes, in which case, the major cost contributor for the plant owner would be eliminated.

With the elimination of hardware changes, it is estimated that procedural and TS changes can be developed for $190,000/plant or $0.9M for all 47 plants. NRC costs are estimated to be 60% of the hardware-related NRC costs. Thus, without the hardware changes, for the expected value of risk reduction the value/impact score is given by:

$$S = \frac{6{,}560 \text{ man-rem}}{\$(0.9 + 0.3)M}$$

$$= 5{,}470 \text{ man-rem/\$M}$$

Other Considerations

The frequency of overpressure events may be higher than the estimate used which was based solely on the number of events that have occurred. Other failure modes are possible, with failure of the PORV a prime example. The frequency of events that initiate overpressure transients and would now challenge the OMS is probably unchanged from the pre-1979 level (about 0.13/RY). However, the OMS prevents these events from becoming overpressure events. Even if the unavailability of the OMS were 0.01/demand, the frequency of overpressure excursions would be increased by only 10% from the estimate that was used.

The analysis assumed that a brittle failure of the reactor vessel will always result in a core-melt accident. However, depending upon the break type and size, the amount of decay heat generated by the fuel, and the location of the

790. NUREG/CR-3384, "VISA - A Computer Code for Predicting the Probability of Reactor Pressure Vessel Failure," U.S. Nuclear Regulatory Commission, September 1983.

792. AEOD/C401 "Low Temperature Overpressure Events at Turkey Point Unit 4," Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, March 1984.

793. Memorandum for B. Sheron from B. Liaw, "Additional Low-Temperature-Overpressure Protection (LTOP) Issues for Light-Water Reactors," August 30, 1984.

794. Memorandum for K. Seyfrit from E. Imbro, "Single Failure Vulnerability of Power Operated Relief Valve Actuation Circuitry for Low Temperature Overpressure Protection (LTOP)," October 24, 1984.

ISSUE 99: RCS/RHR SUCTION LINE VALVE INTERLOCK ON PWRs

DESCRIPTION

Historical Background:

On April 17, 1984, a DSI memorandum[796] on the subject of RHR interlocks for W plants described staff concerns that the design basis for RHR interlocks had been misunderstood and that these concerns had not been adequately pursued in recent reviews. As a result, DST was requested to prioritize this concern as a generic safety issue.[797]

Interlocks are provided to assure that there is a double barrier (two closed valves) between the RCS and RHR systems when a plant is at normal operating conditions, i.e., pressurized and not in the RHR cooling mode. A related issue (Issue 96) addresses the concern of assuring that both series RHR isolation valves are closed during normal power operation. Issue 99 is concerned with the inadvertent closing of these valves when the RHR system is in use.

Two basic features are incorporated in the interlock design: (1) an automatic closure signal on high RCS pressure (typically 600 psig), and (2) a block of the manual open signal at a lower RCS pressure (typically 425 psig). The auto-closure setpoint is generally set higher than the design pressure of the RHR system. However, overpressure protection of the RHR system during RHR cooling is provided by relief valves and not by the slow-acting RHR suction valves. The block setpoint is lower than the RHR system design pressure to preclude opening of either RHR suction valve when the RCS is at a higher pressure.

In the W design, 2 interlock channels are provided such that 1 channel is used to interlock the operation of one RHR suction valve and the other channel is used for the other valve. The same interlock configuration is used in W plants for designs that have 1 or 2 RHR drop lines from the RCS. When either channel is in a tripped state, its associated suction valve will automatically close if it is open. Since the relays used for this interlock are deenergized to initiate valve closure, a loss of the instrument bus used for either channel will result in a loss of RHR cooling due to inadvertent closure of one of the suction valves.

Safety Significance

The loss of one instrument bus or disablement of one logic channel will result in the automatic closure of one of the RHR suction line isolation valves. In the RHR cooling mode, such closure gives rise to the potential for RHR pump damage and loss of decay heat removal by the RHR system. This safety concern applies to all W reactors.

Possible Solutions

The proposed resolution to this issue that was assumed for cost estimation purposes consists of the following parts:

(1) Review and document the design basis for the RHR suction valve interlock.

(2) Develop interim operating procedures until changes to the logic and control for the RHR system can be implemented.

(3) Change the logic configuration that controls the valves from a one-of-one configuration to a two-of-two configuration. Improvements in detecting and alarming of the loss of RHR coolant flow would be made.

(4) Changes to the plants' TS.

PRIORITY DETERMINATION

Frequency Estimate

NSAC-52[798] lists 27 events through 1981 that involved loss of RHR flow due to suction valve closure. Two of these events occurred as the result of a pressure rise in the primary system. The other 25 events resulted from causes other than an actual pressure rise and occurred during 206 RY of operating experience at PWRs. This experience results in a frequency of 0.12 unplanned RHR suction valve closures per plant-year. Of these 25 closures, 22 events involved the closure of only 1 valve and 3 events resulted in the closure of both valves. Thus, 88% of the reported events were independent channel failure events and 12% can be potentially classified as common-cause related.

When in the refueling mode and the water level is 23 feet above the core, only one RHR train must be operable. Closing the suction valve could cause cavitation and damage to the pump and leave no RHR train operable. However, it would take many hours for the level to boil down and uncover the core. RHR cooling could be restored in a few hours. In addition, the fuel pool cooling system could be used. Therefore, this case would have a small associated risk.

In all other modes, two RHR trains are required to be operable while only one is usually operating. If the RHR valves close causing cavitation and damage to the operating RHR pump, the other RHR train would still be operable. The NSAC data[798] show that the operator successfully reopened the inadvertently closed valves immediately in all but one event. In this event at Davis-Besse, it took 2.5 hours to restore RHR cooling because of the need to refill and vent the system. Yet, in this lengthy delay, no sustained damage occurred to the system components. However, due to the long time interval involved before restoring RHR cooling, this event was counted as an RHR system failure. Thus, an unavailability of 0.04 is assumed but believed to be overly conservative. If the valve cannot be reopened, either the steam generators or the charging pumps could be used as alternate means of cooling.

Based upon engineering judgment, the unavailability of the main and/or auxiliary feedwater during RHR operation is estimated to be 0.1 and the unavailability of the charging pumps is estimated to be 0.01. These may be overly optimistic since there is no TS requirement for the availability of these systems in the cold shutdown modes. Further, maintenance and testing is often performed on these systems during the RHR cooling modes. Thus, the unavailability of core cooling is estimated to be the product of (0.12 event/RY)(0.04)(0.1)(0.01) or 4.8×10^{-6}/RY which, assuming no further actions are taken, becomes the expected core-melt frequency resulting from an inadvertent closure of one or both RHR suction valves.

Changing the logic system from a one-of-one system to a two-of-two system will reduce the independent failure frequency contribution of one valve closure from 0.12/RY to 0.003/RY. With the common mode contribution remaining the same (0.015/RY), the revised frequency of incorrect valve closures reduces to 0.018/RY by the revised logic configuration. Improved procedures and alarms are assumed to reduce the human error of failing to reopen the RHR isolation valves from 0.04 to 0.02 per event. The changes in failure rates reduce the expected core-melt frequency from an RHR valve being closed to (0.018)(0.02)(1)(0.01)/RY or approximately 3.6×10^{-7}/RY. This represents a core-melt frequency reduction of 4.4×10^{-6}/RY.

Consequence Estimate

The expected radiological consequences from this issue are expressed in whole body man-rem dose based upon the radioactive release categories described in WASH-1400.[16] The computer program CRAC2[64] applied to a typical midwest site meteorology (Braidwood) was used for the dose calculation. An average population density of 340 persons per square mile was used over an area which extended from an exclusion zone of one-half mile about the reactor out to a 50-mile radius about the reactor.

A core-melt resulting from the loss of the RHR system would result in an accident similar to the T_1MLU sequence described in the Oconee RSSMAP analysis.[54] The release, given a core-melt, occurs in the following categories with the respective probability and dose:

Category	Probability	Dose (man-rem)
3	0.5	5.4×10^6
5	0.0073	1.0×10^6
7	0.5	2.3×10^3

A core-melt frequency reduction of 4.4×10^{-6}/RY results in a dose reduction of 12 man-rem/RY. For the 30 existing reactors with an average remaining life of 27.7 years and 28 new plants with an expected life of 30 years, the total risk reduction for this issue amounts to 20,000 man-rem.

Cost Estimate

Industry Cost: The cost estimate addresses the four actions proposed as the resolution of this issue. The review and documentation of the design basis of the RHR suction valve interlocks is expected to require 4 man-weeks which, at a rate of $2,270/man-week, results in a cost of $9,080/plant. The development of interim operating procedures and operator training is estimated to total 5 man-weeks/plant or $11,350/plant. Hardware costs to modify the logic system and install the RHR flow alarms are estimated to be $4,000. An additional 6 man-weeks ($13,620) will be required for engineering and installation costs. The total hardware modification cost is estimated to be $17,600. TS changes are estimated to take 4 man-weeks or $9,080. Thus, the costs for issue resolution are estimated to be $47,200/plant. Plants not having an operating license are expected to have a lesser cost but, due to the advanced stages of construction, the reduction is not expected to be significantly less. Modifications to plant hardware are expected to be performed during a refueling outage and would obviate the need to include replacement fuel costs. No significant additional maintenance costs over the currently existing configuration are envisioned. Thus, for all 58 plants, the total industry cost is estimated to be \$2.7M.

NRC Cost: It is estimated that NRC costs associated with the issue resolution can be accommodated in a total of 8 man-weeks or \$38,000.

Thus, the total cost associated with the resolution of this issue is \$(2.7 + 0.038)M or approximately \$2.74M.

Value/Impact Assessment

Based on an estimated public risk reduction of 20,000 man-rem, the value/impact score is given by:

$$S = \frac{20{,}000 \text{ man-rem}}{\$2.74\text{M}}$$

$$= 8{,}000 \text{ man-rem/\$M}$$

Other Considerations

The analysis did not consider the possible increase in the chance of an interfacing systems LOCA which might result because the logic changes reduced the reliability of the interlock function. It is presumed that the reliability of a one-out-of-one logic is the same as a two-out-of-two logic.

The ORE is estimated to be 2.25 man-rem/plant for work involved with hardware modifications inside the containment. This would result in a total worker dose of 176 man-rem. The accident avoidance occupational dose reduction is estimated to be 146 man-rem.

The industry cost savings due to accident avoidance are estimated to be (4.4×10^{-6} accident/RY)(\$1.65 billion/accident) or \$7,260/RY.

Consideration also should be given to those cost savings which result from the prevention of incidents producing long interval RHR inoperability, but do not result in damage to the core. Such incidents may result in plant shutdown longer than anticipated to investigate the causes of the inoperability and to assure the adequate corrective actions have been taken. Assuming that the outage extension lasts 2 weeks, the replacement power costs (estimated at \$500,000/day) are \$7M. At the current frequency of long interval outage events, the savings per plant resulting from incident avoidance are \$90,000.

CONCLUSION

Based on the averted public risk and the value/impact score, this issue has a HIGH priority ranking. The public risk may be underestimated if the feedwater and injection alternatives are not as available as predicted.

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.

54. NUREG/CR-1659, "Reactor Safety Study Methodology Application 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.

796. Memorandum for R. Mattson from T. Dunning "RHR Interlocks for Westinghouse Plants," April 17, 1984.

797. Memorandum for F. Rowsome from W. Houston, "RCS/RHR Suction Line Valve Interlock on PWRs," August 27, 1984.

798. NSAC-52, "Residual Heat Removal Experience Review and Safety Analysis; Pressurized Water Reactor," Nuclear Safety Analysis Center, January 1983.

ISSUE 103: DESIGN FOR PROBABLE MAXIMUM PRECIPITATION

DESCRIPTION

Historical Background

The issue of using the most recent NOAA procedures for determining probable maximum precipitation (PMP) was raised[683] after an OL applicant disputed the NRC use of NOAA Hydrometeorological Report (HMR) Nos. 51 and 52,[684] published in June 1978 and August 1982, respectively. The PMP values are used in estimating design flood levels at reactor sites. It was the contention of the applicants that the use of HMR-52, which in general results in higher flood levels than those obtained using earlier reports, was inappropriate and constituted an unauthorized backfit under NRC procedures. HMR-51[685] issued by NOAA in June 1978 expanded the information previously presented in HMR-33[686] (cited in SRP[11] Section 2.4.2). This expansion extends the precipitation duration from 48 to 72 hours and increases the drainage areas from 1,000 to 20,000 square miles. In addition to other provisions, HMR-52[684] provides techniques for analyzing PMP for drainage areas of 1 square mile and durations of 1 hour and less.

GDC-2 requires that design bases for floods reflect consideration of the most severe historical data with sufficient margin for the limited accuracy, quantity, and period of time in which data have been accumulated. Guidance on what constitutes sufficient margin is contained in Regulatory Guides 1.59[687] and 1.102.[688] These documents state that the appropriate design basis for precipitation-induced flooding is the probable maximum flood (PMF) as developed by the U.S. Army Corps of Engineers. This PMF criterion has been used by NRC since 1970. Thus, in the case of floods, the PMF is the criterion that has been used to meet GDC-2.

Procedures for estimating PMFs are given in Appendices A and B of Regulatory Guide 1.59[687] (Appendix A has since been superseded by ANSI N170-1976). ANSI N170-1976 defines PMF as a hypothetical flood that is considered to be the most severe reasonably possible, based on comprehensive hydrometeorological application of PMP and other hydrologic factors favorable for maximum flood runoff. Thus, PMP is an integral component of PMF determination. Section 5.2 of ANSI N170-1976 states that PMP estimates for the U.S. are available in generalized studies prepared by the National Weather Service (NWS), these estimates are presented in varying degrees of completeness. Specific PMP estimates for areas not adequately covered by these studies may be made by using techniques similar to those employed by NWS.

Recognizing the importance of using the most recent engineering technology in evaluating the potential impacts on reactor site safety, SRP[11] Section 2.4.2 was written to allow "...improvements in calculational methods..." With the publication of HMR-51[685] and HMR-52,[684] OL applicants were requested by the staff to assess the effects of their use on plant safety.

Safety Significance

Improper drainage at reactor sites during heavy rainfalls can lead to flooding that can render safety-related equipment inoperable.

Possible Solution

In all cases reviewed by the staff against HMR-51 and HMR-52, the issue has been resolved by the applicants taking the following actions: (1) site drainage has been designed to handle the increased design basis precipitation, (2) commitments were made to develop procedures to assure that critical entrances to buildings will be closed, and (3) curbs were installed at critical entrances.[639] In order to clarify the staff's position and remove ambiguities from the SRP,[11] it will be necessary to revise SRP[11] Sections 2.4.2 and 2.4.3. This solution will be a forward-fit and will incorporate the most recent technical advances for determining PMP that are known at the time that the SRP revision is made. Future technical advances in the determination of PMP will also require revisions to the SRP.

CONCLUSION

Revisions to SRP[11] Sections 2.4.2 and 2.4.3 are presently underway for application to CPs and OLs and will be reviewed by CRGR.[691] Due to an appeal on the use of HMR-51 and HMR-52, NRC suspended[690] routine requests for NTOL review of their site flooding assessments under the new NWS procedures of HMR-51 and HMR-52. The staff is currently making these assessments. Thus, the solution to this issue has been identified, but must be analyzed for its applicability to operating reactors.

REFERENCES

11. NUREG-0800, "Standard Review Plan," U.S. Nuclear Regulatory Commission.

683. Memorandum for W. Johnston from R. Ballard, "Disputed Procedures for Estimating Probable Maximum Precipitation," January 13, 1984.

684. Hydrometeorological Report No. 52, "Application of Probable Maximum Precipitation Estimates - United States East of the 105th Meridian," U.S. Department of Commerce, National Oceanic and Atmospheric Administration, August 1982.

685. Hydrometeorological Report No. 51, "Probable Maximum Precipitation Estimates, United States East of the 105th Meridian," U.S. Department of Commerce, National Oceanic and Atmospheric Administration, June 1978.

686. Hydrometeorological Report No. 33, "Seasonal Variation of the Probable Maximum Precipitation East of the 105th Meridian for Areas from 10 to 1,000 Square Miles and Durations of 6, 12, 24 and 48 Hours," U.S. Department of Commerce, April 1956.

687. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, August 1977.

688. Regulatory Guide 1.102, "Flood Protection for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, September 1976.

689. Memorandum for V. Stello from H. Denton, "Potential Generic Requirement Concerning Design for Probable Maximum Precipitation," June 25, 1984.

690. Memorandum for V. Stello from H. Denton, "Generic Requirements Regarding Design for Probable Maximum Precipitation," October 10, 1984.

691. Memorandum for H. Denton from V. Stello, "Generic Requirements Regarding Design for Probable Maximum Precipitation," August 8, 1984.

ISSUE 111: STRESS CORROSION CRACKING OF PRESSURE BOUNDARY FERRITIC STEELS IN SELECTED ENVIRONMENTS

DESCRIPTION

Historical Background

Indications of possible stress corrosion cracking (SCC) in the Indian Point Unit 3 (IP-3) steam generator prompted MTEB to review foreign and domestic operating experiences related to possible indications of SCC in low-alloy ferritic steels. The incidents identified[837] as possible precursors to generic concerns of SCC relate to BWR reactor vessels and PWR steam generators. These events and some additional information that are reviewed and discussed in this evaluation include:

(1) A through-wall crack in the transition cone of the steam generator shell at IP-3.

(2) A through-wall crack in the lower head closure weld region of the Italian Garigliano steam generator (an indirect cycle BWR similar to a BWR-1).

(3) A guillotine rupture of a transition cone (reducer) in the secondary piping of the German HDR test facility.

(4) Cracking of feedwater lines in W PWRs.

(5) Other events that may contribute to SCC in BWR reactor vessels and PWR steam generator vessels.

(6) Inferences from materials testing.

The materials of interest are those low-alloy ferritic materials (SA-533 Grade B, SA-508 Grade 2, and SA-302 Grade B) used in the fabrication of the subject pressure vessels.

Safety Significance

The reactor vessels and steam generators are constructed of low-alloy ferritic steels and designed to the ASME Codes. The ASME Codes are linked to fatigue crack initiation in chemically unreactive environments (ASME Section III) and fatigue crack growths of existing defects as part of the ASME Section XI inspection Code. Even though a corrosion allowance is specified in the ASME Codes as a design consideration, it is not linked to corrosion fatigue or SCC that may occur in active chemical environments such as those experienced in the nuclear pressure vessels (reactor pressure vessels, steam generator pressure vessels).

Should the materials used in the pressure vessels be susceptible to SCC and exceed the inherent allowances in the ASME design/inspection Codes, a vessel rupture could result in a core-melt and radiation doses to the public. This issue affects the design and operation of all LWRs except those designed by B&W.[859]

Possible Solution

Prior to developing a solution to this problem, MTEB proposed a research scoping effort to define the severity of the problem and the conditions under which the SCC phenomena are likely to be exacerbated. The research effort would also involve laboratory testing of the low-alloy materials in reactor-grade water with variable oxygen, chloride, and copper as possible water chemistry constituents.

No risk reduction can be attributed to the study (scoping) efforts. However, the proposed effort is expected to better define under what conditions SCC of the pressure boundary steels may occur and if such conditions arise or prevail during reactor operations. The proposed effort would also involve determinations of the effectiveness of post-weld heat treatments (PWHT) and water chemistry excursions that may affect the materials resistance to SCC. The results of these studies (research) could then possibly be used to determine when and where to conduct inspections to detect the cracks before they become a safety concern.

PRIORITY DETERMINATION

In order to develop background frequency information to establish the safety significance of this issue, a review and discussion of the incidents identified above was required.

IP-3 Steam Generator Event: During a refueling outage (with the reactor in a cold shutdown condition) on March 27, 1982, a small leak was detected on the shell side of steam generator #32 of IP-3. The leak originated in the circumferential weld joining the transition cone to the upper shell. The steam generator shell is constructed of SA-302 Grade B material approximately 4 in. thick. To characterize the cracking phenomenon, the utility had various samples removed for metallurgical evaluation and failure analyses. BNL performed an independent failure analysis on specimens from steam generator #32 and on three additional boat samples containing cracks cut from steam generator #31. OIE issued Information Notice No. 82-37[842] to inform the industry of the event. W informed[843] the NRC staff that no indications similar to those observed at IP-3 were identified in the inspections performed on steam generators in 12 plants.

An investigation by BNL as reported in NUREG/CR-3281[844] concluded that the cracking was caused by a low cycle corrosion fatigue phenomenon with cracks initiating at areas of localized corrosion (pits) and propagating by fatigue. The cause of the pitting/cracking was considered to be related to the unit's relatively high operating dissolved oxygen levels and copper species in solution. The report also concluded that SCC could not be entirely discounted as the possible failure mechanism. NUREG/CR-3281[844] also identified that IP-3 had developed moderate to severe denting of the steam generator tubes. The sludge analysis in IP-3 showed concentrations as high as 45% copper and 40% iron. Significant amounts of chlorine (Cl), copper as cuprous oxide (Cu_2O), and alpha hematite (alpha-Fe_2O_3) were also present in the sludge pile. The presence of these constituents indicated that water chemistry control in the IP-3 steam generators had been poor for a considerable period of time. Additionally, in January 1981, IP-3 experienced a turbine blade failure which damaged approximately 50 condenser tubes and allowed chloride into the steam generators with recorded levels of up to 325 ppm. The chloride intrusion may have had some influence in initiating pits at the inside surface of the steam generator shell.

Results from constant extension rate tests (CERT) on SA-302 Grade B material in neutral and chloride solutions were reported in NUREG/CR-3614.[845] The CERT were performed on weld and base metal samples in air, water, and chlorine solutions. The chlorine solutions as Sodium Chloride (NaCl) and Cupric Chloride ($CuCl_2$) ranged from 1 ppm to 325 ppm chlorine. The results of the test indicated no significant effect in the NaCl CERT. However, the $CuCl_2$ CERT indicated possible susceptibility of the SA-302 Grade B material with as little as 1 ppm chlorine (as $CuCl_2$) in 268°C water. No attempt was made to control the dissolved oxygen content in the water. The combined results appear to indicate that copper as $CuCl_2$ may significantly alter the electrochemical reaction. The IP-3 secondary water chemistry may, however, provide an even different corrosion mechanism than that of the CERT. In this regard, the electromotive force series of metals could also produce galvanic corrosion of the iron (Fe) in the presence of copper because carbon steel is anodic compared to copper (Cu) in the galvanic series. Thus, pitting/crevice corrosion of the carbon steel may have been acting as a combination of galvanic corrosion and low cycle fatigue. In the latter case, corrosion products in cracks (crevices) may act as wedges during cooldowns causing crack extensions. During heatups, newly-exposed crack surfaces develop more corrosion deposits. Repeated cycles, therefore, may result in through-wall cracks (corrosion-fatigue).

Because of the poor secondary water chemistry control at IP-3, the atypical massive chloride intrusion, and the results of the W inspections on other steam generators, the event at IP-3 may not represent a generic PWR condition but a plant-specific combination of atypical events. However, because of uncertainties in the CERT to represent conditions that may have prevailed at IP-3, and the indications from the CERT of the potential for copper in solution to effect some form of corrosion-related attack on the low-alloy materials, these effects cannot be ruled out as a potential generic concern, especially when considering the PWR secondary water chemistry controls that have existed in the industry (see "Other Conditions" contributing to SCC).

Garigliano Steam Generator Event: The Garigliano steam generator crack developed at the inner surface of the water box circumferential weld between the tube sheet and the nozzles on the primary side (August 1978). The through-wall crack propagated through the Monel clad and the SA-302 Grade B shell (approximately 2 inches thick). GE conducted an extensive investigation and reported[846] its results to the NRC. The most pertinent information revealed that the crack propagation resulted from environmentally-assisted corrosion under sustained loads (SCC). Manganese sulfide as segregates were evident in the monel and base metal with the presence of sulfur in the region of crack tips. Therefore, aggressive acidic crack-tip chemistry caused by dissolution of the sulfide inclusions were concluded by GE to be contributors to the SCC. Local PWHT of the weld with unknown control was also reported by GE to have resulted in high residual stresses in the region of the weld. The high oxygen content (~200 ppb) in the coolant medium was not considered atypical, but it may have enhanced the electrochemical reaction involved in the crack initiation and propagation.

GE concluded that the conditions that prevailed in the Garigliano steam generator (high residual stress, material sulfur content and inclusions) were atypical of current domestic BWR design and PWHT. The NRC staff did not challenge the GE position. Therefore, the Garigliano event was not considered a generic event typical to domestic operating BWRs. However, the effects of sulfur content in the material and the potential contribution to SCC have since been subject to further tests and evaluations (see discussion on material testing). One might argue in hindsight that the Garigliano event could have been a precursor to the SCC susceptibility of high/low sulfur content low-alloy steels in reactor grade water.

HDR Rupture Event: NUREG-1061,[611] Volume 3, describes the double-end guillotine break that occurred in the HDR test facility on November 3, 1983. The reducer (conic section) that failed was fabricated from a single billet of 15 Mo 3 steel. The wall thickness of the conic section was approximately one-fourth the design thickness. Therefore, the combined primary, secondary, bending, and notch stress concentrations could have resulted in a stress intensity of nearly two orders of magnitude above the design stress. This fabrication error could well have resulted in exceedance of some stress threshold that caused the failure. The thinness of the conic wall section and the high oxygen content (~8ppm) may also have contributed to the failure. The atypical design and fabrication errors related to the HDR failure are believed sufficient to preclude this event as representative support of this issue as a generic issue. It should be pointed out that, although the stresses were very high, there was no gross plastic deformation and no ductility exhibited on a microscale.[857] It was a brittle fracture. The failure is atypical of fatigue in that there were numerous initiation sites. These facts point to stress corrosion cracking of low alloy/carbon steels as the failure mechanism. This incident is cited to demonstrate the mechanism.

PWR Feedwater Line Cracking Events: These failures are being addressed in Issue 14. The primary failure mode has been identified as thermal fatigue (not CF or SCC) resulting from coolant stratification. The PWR Pipe Crack Study Group completed its investigation of this issue and published its findings in NUREG-0691.[13] Based on the above findings, any SCC that may or may not have influenced the resulting failures were masked by the thermal fatigue constituent.

Other Events Contributing to Potential SSC: Intrusion of chloride, sulfide, copper, and other contaminants into the BWR reactor water and PWR secondary water may contribute to SCC of the vessels materials. EPRI NP-1136[847] stated that 20 BWR plants over a 33-month time period (1974-1977) indicated 12 forced outages as a result of high conductivity in the reactor water or heavy condenser tube leakages. On an average, this amounts to 307.22 significant contaminant intrusions per BWR reactor-year. EPRI NP-2230[307] reported 6 condenser leakages over 172 RY of PWR operation. This amounts to a frequency of 0.03 contaminant intrusions from condenser leaks into the PWR secondary cooling water of the steam generators.

As a further example of other apparent poor PWR secondary water chemistry operations (in addition to the IP-3 sludge analyses discussed earlier), the sludge deposits in the removed Surry 2A steam generator undergoing tests at Hanford were reported in NUREG/CR-3842.[849] Analyses of the Surry sludge deposits revealed 35 to 60 percent metallic copper, 20 to 30 percent Hematite (Fe_2O_3), and 10 percent Cuprite (Cu_2O). All the analytical data on the sludge samples indicated that they originated from the secondary side. The high copper content probably originating from the condenser tubing (see "Other Considerations").

Tighter requirements for the BWR reactor water may account for the reported higher frequency of contaminant intrusion in BWRs from condenser tube leaks. However, Regulatory Guide 1.56[848] provides methods determined acceptable by the NRC staff to maintain high purity water in the BWR reactor water cycles and to minimize failure of the reactor vessel from mechanisms of general corrosion and SCC induced by impurities in the reactor coolant.

For the secondary side of the PWRs, resolution[850] of USIs A-3, A-4, and A-5 contained staff recommendations that the PWR plants incorporate Revision 3 to SRP[11] Section 5.4.2.1 as plant-specific programs for secondary water chemistry control.

From the above limited data, condenser tube leaks in BWRs and PWRs have been frequent. However, the water purity requirements for BWR plants should alleviate potential corrosion effects to the BWR reactor vessels. For the PWR steam generators, adoption of the secondary water chemistry guidelines may reduce future corrosion potentials, but not necessarily resolve the effects of existing corrosion damage.

Based on the IP-3 experience, the above-described Surry sludge analyses, the recent Surry Unit 2 inspections discussed in "Other Considerations," and the fact that steam generator tube degradations have been linked to variable PWR secondary water chemistry controls,[840] it appears reasonable to equate the adequacy of the steam generator secondary water chemistry environment to conditions that may also enhance SCC in the steam generator vessel shells.

<u>Inferences from Materials Testing</u>: A considerable amount of materials research and testing has been performed on the SA-508 and SA-533 reactor vessel materials and has resulted in the publication of several documents: NUREG/CP-0058,[851] Vol. 4; NUREG/CP-0044,[852] Vol. 1 (pp. 7, 91, 141, 179); NUREG/CP-0044,[852] Vol. 2 (pp. 27, 91); Reference 853; and NUREG/CR-4121.[854]

The research and testing were performed in typical PWR and BWR reactor water chemistries. The research results also included comparisons with the ASME Section XI air and water fault lines. Based on the existing research results, the following generalizations appear appropriate for these materials:

(1) There is a trend toward increased crack growth rate with higher material sulfur content.

(2) A higher dissolved oxygen content results in higher initial crack growth rate, but the crack growth rate is stifled with crack depth such that after an initial period of crack growth rate the effects of

the bulk solution dissolved oxygen content diminishes. Therefore, there is little difference in the effective crack growth rates of these materials in BWR and PWR reactor water chemistries.

(3) The crack growth rates for reactor pressure vessel materials are within, or consistent with, the ASME Section XI surface (wet) fault lines.

The most significant effect observed was the high/low sulfur content (material variability), and not the oxygen content (environmental variability). The aqueous solutions used in the referenced research did not contain copper in solution, but some tests did contain small amounts of chlorine in solution.

The only research test results obtained for the SA-302 Grade B base material and associated weld material are reported in NUREG/CR-3281[844] and NUREG/CR-3614.[845] These results were discussed in the earlier IP-3 comparisons.

Based on the above discussions, the differences in the dissolved oxygen contents for the BWR and PWR reactor water chemistries are estimated to have little or no effect on the probability of increased crack growth rates for the reactor pressure vessels. Only limited information was available for the (SA-302 Grade B) pressure vessel material. In the presence of the simulated and degraded PWR secondary water chemistry, the SA-302 material may be susceptible to some form of accelerated corrosion attack.

Frequency/Consequence Estimate

BWR Reactor Pressure Vessel Rupture Frequency Estimate: A nominal base case pressure vessel rupture frequency of 10^{-7}/RY is assumed reasonable for the BWR reactor vessels.[16] In consideration of (1) research results of the reactor vessels materials in their respective reactor water chemistry environments, the vessel materials crack growth rates are within the ASME code limits, (2) the protective corrosion shield provided by the cladding on the inside surface of the reactor vessels, and (3) the BWR reactor water chemistry requirements described earlier, no significant increase in the BWR reactor vessel rupture frequency from SCC is anticipated. However, to provide a coarse estimate, it is assumed that a 25% increase in the BWR reactor vessel rupture frequency can be attributed to SCC. This potential increase in BWR reactor vessel rupture frequency is based on the percentage of stainless steel pipe ruptures attributed to SCC reported in NUREG-1061,[611] Volume 1. Because of the observed prominence of SSC in stainless steel pipes, it seems unlikely that the percentage of reactor pressure vessel ruptures due to SCC would exceed 25% of the total vessel rupture frequency without prior history of this condition. The change in BWR reactor pressure vessel rupture frequency that may be attributed to SCC is therefore estimated to be 2.5×10^{-8}/RY.

BWR Consequence Estimate: Assuming that SCC provides a potential change in the BWR reactor vessel rupture frequency (2.5×10^{-8}/RY), the probabilities of radioactive releases in BWR categories 2 and 3, as described in WASH-1400,[16] are 0.1 and 0.9, respectively. Assuming a 1120 MWe BWR, meteorology typical of the Braidwood site, and a surrounding uniform population density of 340 persons per square mile, the public radioactive risk within a 50-mile radius is

0.113 man-rem/RY. Considering a remaining reactor life of approximately 30 years, the public risk is 3.5 man-rem/reactor.

PWR Frequency and Consequence Analyses: A leak or rupture of a single steam generator would likely produce a rapid cooldown of the reactor similar to an inadvertent full-opening of the turbine bypass valves or a main steam line break.[16] The containments are capable of sustaining a complete blowdown of a steam generator. Therefore, rupture of a single steam generator with no additional failures has no significant risk to the public from core-melt or radioactive releases through containment failures. The plant operations and operation responses to such an event are assumed similar to those described in Item A-22 for a steamline break inside containment. In addition, subsequent and detailed staff evaluations on PWR responses to MSLB with concurrent SGTRs and SBLOCAs were reported in NUREG-0937[860] which concluded that a MSLB inside containment (similar to a steam generator rupture) would likely be bounded by the FSAR analyses and not result in a core-melt.

For a steam generator rupture to lead to a significant release (core-melt), the rupture must be accompanied by damage to the RCS and failure of the ECCS, or failure of the AFWS and the ECCS. The following sections will address these PWR systemic events.

PWR Steam Generator Rupture (SGR) Frequency Estimate: WASH-1400[16] estimated that the SGR frequency was similar to the RPV rupture frequency (10^{-7}/year). Considering approximately 3 steam generators per reactor, the base case SGR frequency is 3×10^{-7}/RY.

To assess the potential increase in SRG frequency as a result of accelerated SCC or CF from PWR secondary water chemistry variability between plants, we reason the following: (1) plants with clean secondary water chemistry will have an SGR frequency equal to the above base case rupture frequency (3×10^{-7}/RY), (2) plants that have experienced medium degradations of the steam generator tubes will have an SGR frequency one order of magnitude greater (3×10^{-6}/RY) than the base case, (3) plants that have experienced severe degradations of the steam generator tubes will have an SGR frequency two orders of magnitude (3×10^{-5}/RY) greater than the base case rupture frequency of 3×10^{-7}/RY.

The above SGR frequency (3×10^{-5}/RY) is back-calculated to estimate the number of steam generator leaks that have occurred by using the piping leak-before-break ratio of 20.[16] The predicted number of leaks based on the above reasoning is $(3 \times 10^{-5}/RY)(500\ RY)(20) \sim 0.3$. Likewise, if we estimate that steam generator ISI has a 10% chance of not detecting cracks in the steam generators before they develop into leaks, 3 steam generators with cracks could be expected. Compared to the 7 steam generators where cracking has been detected, the above crude estimates are fairly good, but a better correlation with leaks and cracks would be obtained from an SGR frequency of 10^{-4}/RY. For comparative purposes, the probability of a MSLB is also 10^{-4}/RY.

Alternately noting that no rupture has occurred in 1500 steam generator years (500 RY) and ignoring the current steam generator ISI experiences for leak-to-crack detection (1/7) and leak-before-break experiences in U.S. and foreign plants (2 leaks with no ruptures), we would estimate an SGR frequency of

10^{-3}/RY. The SGR frequency of 10^{-3}/RY therefore represents a bounding but prudent estimate. Ignoring the ISI crack detection capability and leak-before-break experiences appears prudent because of the uncertainties in estimating these early warning indicators. As an example of the conservatism of ignoring the crack detection capability, a very conservative staff fracture mechanics analysis[839] estimated that a catastrophic rupture of the steam generator would only be predicted to occur from a complete circumferential crack (360°), with a crack depth approaching one-half the vessel wall thickness. A crack of this magnitude seems very likely to be detectable. Therefore, the SGR frequency may range from a best estimate value of 10^{-4}/RY to an upper bound estimate of 10^{-3}/RY.

PWR Steam Generator Support (SGS) Failure and LOCA Frequencies: If cracks develop in the steam generator vessel shells, it was independently judged[16,859] that the steam generator would likely leak before rupture. The SGR event would therefore most likely be bounded by the MSLB event previously discussed. However, should a catastrophic SGR occur, the steam generator reaction loading to the SGS structure is highly uncertain. In recognition of this, we will assume the conditional failure probability of 0.5 for the SGS (SGS/SGR). The SGS/SGR = 0.5 infers that the SGS is as likely to fail as not to fail. Given failure of the SGS, we assume the conditional probability of a large break LOCA (LBLOCA), given a SGS failure, is 1.

PWR Core-Melt Frequencies: The systemic events that are assumed to lead to core-melt conditions as a result of a catastrophic SGR are: (1) damage to the RCS (LBLOCA), and (2) failure of the ECCS in the unaffected loops, or failure of the AFWS and the ECCS in the unaffected loops. The estimated upper bound core-melt frequencies for these sequences are as follows:

Failure Event	Frequency/RY
SGR	10^{-3}
SGS/SGR	5×10^{-1}
LBLOCA/SGS	1
ECCS Failure	10^{-2}
	$\Sigma = 5 \times 10^{-6}$

Failure Event	Frequency/RY
SGR	10^{-3}
AFWS Failure	4×10^{-5}
ECCS Failure	10^{-2}
	$\Sigma = 4 \times 10^{-10}$ (negligible)

PWR Containment Failure Matrix: Containment response to a core-melt accident from the above LBLOCA/SGR can be grouped into separate plant damage states (PDS). The PDS depends on: (1) the availability of equipment or systems to reduce containment temperature and pressure, and/or (2) containment bypass or failure to isolate containment. The PDS descriptions and probabilities resulting from the LBLOCA/SGR are as follows:

Plant Damage State (PDS)

PDS	Description	Probability
A	No containment heat removal or containment sprays	10^{-3} (Reference 16)
B	Containment heat removal and containment sprays available	0.998
V/B	Given B, but containment bypass through failed MSIVs in ruptured steam generator steam line	10^{-3} (Reference 681)

The containment failure modes are similar to those used in WASH-1400.[16] The conditional probability of the containment failure mode for each PDS is shown in the table below:

Conditional Containment Failure Mode[(a)]

PDS	α	δ	$\beta 4$	$\beta 5$	V
A	10^{-2}	0.96	10^{-2}	-	-
B	10^{-2}	-	-	10^{-2}	-
V/B	-	-	-	-	10^{-3}

(a) α, δ, β, V, are the containment failure mode conditional probabilities for missile damage, overpressurization, failure to isolate, and bypass, respectively.

The probability of an α failure mode ($\alpha = 10^{-2}$) from an SGR refers to direct containment failure by missile penetration. For a LBLOCA-induced core-melt, the in-reactor-vessel steam explosion has a probability of 10^{-4} to produce a missile that breaches containment. For purposes of this analysis, the α failure mode probability from missiles generated by the SGR is assumed to be 100 times greater than that from an in-reactor-vessel steam explosion. Therefore, even through an in-reactor-vessel steam explosion is likely to occur from a core-melt, its contribution to containment failure is negligible. The corresponding WASH-1400[16] α release category is a Category 1 release due to the containment failure from a missile generated by the SGR.

Steam produced from the SGR by reactor molten fuel (core-melt) and water in the reactor cavity can fail the containment by overpressurization (δ). This would occur only when containment cooling is lost.[16,860] The probability of overpressurization due to hydrogen burn is assumed negligible because the steam concentration in containment will tend to suppress hydrogen burn propagation. The probabilities of the δ mode failures for PDS A and B are assumed to be 0.96 and zero, respectively. The corresponding WASH-1400[16] release for PDS A and B are Category 2 and Category 3, respectively.

Failure to isolate containment (β failure mode) is assumed to have a probability of 0.01. The $\beta 4$ mode is with containment sprays unavailable and the $\beta 5$ mode is with containment sprays available. The corresponding WASH-1400[16] release categories for $\beta 4$ and $\beta 5$ are Category 4 and Category 5, respectively. The "V" failure mode probability[681] of 0.001 represent containment bypass through the ruptured steam lines in the affected loop with the MSIVs failed open. The conditional PDS = V/B assumes containment sprays are available and the corresponding WASH-1400[16] release category is a Category 3 release.

The basemat melt-through failure mode is a relatively benign failure mode and, with the most likely case of the containment sprays being available, we assume basemat melt-through is precluded.

The LBLOCA assumed to be induced by the SGR may also be accompanied by SGTRs in the affected loop. However, the conditional SGTRs would be dominated by the probability and consequences of the LBLOCA sequences.

PWR Risk Consequences: The PWR risk consequences for a core-melt frequency (5×10^{-6}/RY) resulting from a SGR-induced LBLOCA is 0.4 man-rem/RY. Over a remaining plant life of 30 years, the public risk is 12 man-rem/reactor. The tabulations of the calculated public risk parameters are:

Public Risk Parameters

WASH-1400[16] Release Category	Containment Failure Mode	Release Frequency $(RY)^{-1}$	Conditional Dose/Release (man-rem)	Public Risk (man-rem/RY)
1	α	5×10^{-8}	5.4×10^{6}	0.3
2	δ	5×10^{-9}	4.8×10^{6}	0.02
3	V	5×10^{-9}	5.4×10^{6}	0.03
4	$\beta 4$	5×10^{-11}	2.7×10^{6}	-
5	$\beta 5$	5×10^{-8}	1.0×10^{6}	0.05
Total	-	1×10^{-7}	-	0.4

The release categories and corresponding containment failure modes are described in the Containment Matrix Section above. The release frequencies (Column 3) are the products of the core-melt frequency (5×10^{-6}/RY) and the summed products of the PDS and the conditional containment failure mode probabilities for each PDS provided in the Containment Matrix Section above. The conditional dose (Column 4) is the man-rem per release for each release category. These release doses are based on the fission product inventory of a 1120 MWe PWR, meteorology typical of the Byron site, and a surrounding uniform population density of 340 persons per square mile over a 50-mile radius from the plant site, with an exclusion radius of one-half mile from the plant.

Cost Estimate

Based on discussions with RES, this issue could be incorporated at no additional cost into the long-term research plan which has not been finalized. A near-term effort would involve an initial expenditure of NRC research funds ($265,000). Depending on the outcome of the research results, additional NRC and industry funds may be needed to develop a solution(s). Because of the small risk, no other costs were estimated.

The industry has a significant economic incentive to repair surface cracks in their steam generators, before they develop into through-wall cracks. As an example, repair of steam generator surface cracks at the Surry plant involved removal by grinding (repair welding was not necessary) estimated by MTEB to cost approximately $1M. At IP-3 where a small through-wall crack developed in one steam generator, the repairs involved grinding and weld repairs. MTEB estimated the costs to IP-3 was approximately $8M. In neither of these cases were the plants required to go into forced outage situations. However, should a plant be placed into a forced outage situation as a result of through-wall cracks in the steam generators, the average replacement power costs of approximately $500,000/day, in addition to the repair costs, would likely result in costs well in excess of $8M.

Other Considerations

A comparison[843] was made of the plants reported by W as having been inspected for indications similar to the IP-3 flaw with plants that have experienced severe steam generator tube degradation histories.[840] The comparison indicated that, in general, the plants inspected were not plants with histories of severe steam generator tube degradations. Subsequent inspections of the replaced Surry Unit 2 steam generators have revealed intermittent cracks up to 1/4 in. deep.[856] The cracks were in the transition region that was part of the original steam generator. The transition cone wall thickness in this area is 3.4 inches and is required by design to be at least 2 inches. Because these indications were in the original part of the transition cone, the affected material was exposed to the same poor secondary water chemistry discussed earlier. The cracking of three Surry 2 steam generator shells occurred at the same joint as the four Indian Point 3 steam generator shells. The inspections of the joints have predominantly been by UT methods from the outside of the shell. As experienced in some of the BWR stainless steel piping inspections for SCC, the UT indications were incorrectly ascribed to geometric configuration. In this regard, IE Information Notice No. 85-65[858] has informed the industry of the events at IP-3 and Surry and the experience with UT versus magnetic particle examinations related to crack detection in the steam generators. Therefore, subsequent ISI testing of the SGS should be more reliable and thereby further reduce the chance of an SGR.

CONCLUSION

Based on limited operating experience (one steam generator leak in U.S. domestic plants and one steam generator leak in foreign plants) and expert opinion,[859] steam generator outer shells are more likely to leak than to catastrophically rupture. A significant leak in a steam generator outer shell would be expected to result in plant responses comparable to a transient induced by the inadvertent full-opening of the turbine bypass valves. A larger steam generator leak (small rupture) is expected to be bounded by the MSLB with concurrent SGTRs and SBLOCA as evaluated in NUREG-0937.[860] The detailed analyses[860] determined that such an event would not result in a core-melt accident.

To further bound the probability and consequences of this issue, we have ignored the steam generator crack detection experiences and steam generator leak experiences (that essentially have provided defense-in-depth mitigations to severe steam generator ruptures) and assumed a catastrophic SGR probability of 10^{-3}/RY that leads to a LBLOCA (failure of primary piping loop). Based on this scenario as a bounding analysis, the public risk from an SGR was estimated to be 12 man-rem/PWR. Therefore, the risk reduction potential (3.5 man-rem/BWR plant, 12 man-rem/PWR plant) indicates that this issue is of low safety significance to the public.

The quantified values used in this evaluation contain a number of unquantified uncertainties. However, to the extent judged reasonable, the bounding values are believed to be biased in conservative directions. Thus, these estimates are more sensitivity studies than absolute quantifications and, therefore, only represent the potential safety significance of this issue relative to other issues.

We have also considered other concerns raised by MTEB.[857] "The experience at two plants (IP-3 and Surry 2) of the material failure mechanism that was not addressed in the original design (and raised doubt whether GDC 4 is being met) requires a response by the staff. The research effort promised in the future would be too late to address licensing concerns now, especially for operating plants. Active consideration should be given to placing a higher priority on research efforts to enhance our understanding in order to provide a meaningful, timely response." However, MTEB also concluded [857] that this issue only provides a minimal risk to the public health and safety in terms of the contribution to core-melt probability.

Based on (1) the low public risk for this issue, (2) the MTEB expert opinion that steam generator leaks are more likely than SGRs[859] (currently supported by the IP-3 and Garigliano experiences), (3) existing staff recommendations to the industry to implement improved secondary water chemistry programs,[850] (4) the OIE Information Notice[858] that should promote more reliable steam generator inspections, and (5) the industry economic incentive for resolution, this issue has minimal public risk that will be even further reduced by implementation of the above actions.

However, the MTEB concerns related to the need for a better understanding of the materials cracking phenomenon, potential licensing position(s) related to meeting the original licensing design bases, and whether or not the GDC are met, are considered licensing concerns. Therefore, based on the above evaluations, staff actions already taken, and the above discussions, we recommend that this issue be classified as a Licensing Issue.

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ISSUE 112: WESTINGHOUSE RPS SURVEILLANCE FREQUENCIES AND OUT-OF-SERVICE TIMES

DESCRIPTION

Historical Background

In February 1983, the Westinghouse Owners Group submitted WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," to the NRC for review and approval. This report proposed TS changes governing operability and surveillance testing of the Reactor Trip System (RTS) based on equipment unavailability and risk analyses. The report was reviewed by NRR and accepted with limitations.[822,823]

Safety Significance

The RTS availability is expected to be reduced slightlv, whereas, the number of inadvertent trips should decrease. The frequency of a core-melt due to an ATWS event would increase and that due to an inadvertent trip would decrease. This issue applies to all W PWRs.

Possible Solution

WCAP-10271 proposed, as modified after the Salem trip system breaker problems, four changes: (1) changes to the surveillance or test intervals for the RTS analog channel operational tests from monthly to quarterly; (2) the time allowed for a channel to be inoperable or out of service in an untripped condition would be changed from 1 hour to 6 hours; (3) the time an inoperable channel could be bypassed to perform testing on another channel in the same function would be increased from 2 hours to 4 hours (in conjunction with this test time increase, WCAP-10271 proposes leaving the inoperable channel in a tripped condition and performing the channel test in a bypass condition); and (4) perform routine analog channel testing in the bypassed condition instead of the tripped condition.

PRIORITY DETERMINATION

Frequency/Consequence Estimate

An approximation of the effects which can result from the proposed changes (taken from WCAP-10271) are:

(1)	Increase in Reactor Trip Unavailability	4×10^{-7}/demand
(2)	Increase in ATWS Core-Melt Frequency	5×10^{-8}/RY
(3)	Decrease in Inadvertent Reactor Trip Core-Melt Frequency	7×10^{-8}/RY
(4)	Decrease in Core-Melt Frequency	2×10^{-8}/RY

The insignificant change to core-melt frequency will, in essence, result in little or no reduction to risk.

Cost Estimate

It was calculated in WCAP-10271 that the manpower expended just to do testing on the analog channels would be 3,120 man-hours/RY. Assuming that reducing the surveillance testing from monthly to quarterly will reduce these expenditures by two-thirds results in a savings of 2,040 man-hours/RY or approximately 1 man-year. Assuming a man-year cost of $100,000 and an average life of 26 years for each of the 61 W reactors results in an industry saving of $160M.

CONCLUSION

Since there is essentially no change in risk resulting from this issue, but there is a significant saving in cost, this issue is classified as a resolved Regulatory Impact issue.

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ISSUE 119: PIPING REVIEW COMMITTEE RECOMMENDATIONS

In an August 1983 memorandum,[834] the EDO requested a comprehensive review of NRC requirements in the area of nuclear power plant piping. In response to this request, the NRC Piping Review Committee (PRC) was formed to review and evaluate current regulatory requirements to provide recommendations on where and how the NRC should modify current requirements and to identify areas requiring further action. The scope of the PRC review covered those pipes that are in the safety-related systems and those high-energy lines important to safety in new and operating nuclear power plants. With respect to postulated pipe breaks, the scope covered all high-energy lines.

An NRC steering committee consisting of members from RES, NRR, OIE, and ELD was formed to review and develop a plan for implementing the changes recommended in the PRC report.[611] The steering committee agreed to focus its attention on the recommended research and regulatory changes designated in the PRC report[611] as Category A (high priority) recommendations. The PRC-recommended research and regulatory changes were restructured by the steering committee (combining of research and regulatory recommendations) to form 9 tasks to be addressed by the NRC implementation plan.[835] This issue deals with 5 of the 9 tasks contained in the NRC implementation plan. These 5 tasks consist primarily of NRR regulatory actions and some closely-related research efforts. The remaining 4 tasks of the NRC implementation plan relate only to research activities and are therefore not part of this issue.

This issue primarily involves changes to Regulatory Rules and revisions to Regulatory Guides and the SRP.[11] No significant change in public safety will result from resolution of this issue. However, resolutions to the various items are expected to result in less complex and more realistic approaches to piping design and operation in nuclear power plants. The results should yield more efficient regulatory practices, improve plant piping systems designs, increase plant reliabilities, and decrease ORE associated with inspections and repairs. The NRC steering committee has agreed that, based on the information provided in NUREG-1061,[611] this work should continue on a schedule consistent with high-priority issues. Therefore, this issue is a Regulatory Impact issue for which possible resolutions have been identified. RES will take the lead for resolution of this issue with assistance from other NRC Offices.[835] The following is an evaluation of the 5 parts of this issue.

ITEM 119.1: PIPING RUPTURE REQUIREMENTS AND DECOUPLING OF SEISMIC AND LOCA LOADS

DESCRIPTION

Historical Background

This task combines two PRC Category A regulatory recommendations with one PRC Category A research recommendation. The designations of the three PRC recommendations are: (1) leak-before-break (A-1), (2) decoupling of seismic and

LOCA loads (A-5), and (3) completing research on decoupling (A-4). The resolution of this task will affect all LWRs.

One part of the task involves rulemaking changes to GDC-4 in Appendix A of the 10 CFR 50 to redefine the need to consider the dynamic effects of pipe breaks. A proposed rule to modify GDC 4 was published in the Federal Register on July 1, 1985. This rule change codifies leak-before-break technology but is limited to only the primary loop piping of PWRs. A broad scope rule dealing with all high energy piping in all LWRs is to be published in the Federal Register in November 1985. Revisions to SRP[11] Sections 3.6.1 and 3.6.2 are needed to eliminate the postulation of arbitrary intermediate breaks. The second part of this task would relax the requirement to consider LOCA and seismic loads simultaneously. A revision to SRP[11] Section 3.9.3 will be needed to decouple seismic and pipe rupture loads in the mechanical design of components and their supports.

Safety Significance

The current GDC-4 requirement and SRP[11] Section 3.6.2 pertaining to postulated double-ended guillotine breaks (DEGB) of the largest pipes and postulated arbitrary intermediate pipe breaks need to be changed to include more realistic criteria and to allow consideration and acceptance of validated analysis methods. The requirements of the current GDC-4 have led to a situation where protective devices have been added to forestall events that are extremely unlikely. These protective devices that have been designed for the extremely unlikely events could, however, reduce safety and increase worker radiation exposures from normal operations and more likely design basis considerations.

SRP[11] Section 3.9.3 currently requires that piping systems and associated components be designed for the combined effects of an SSE and a LOCA. There has never been a well-developed rational basis for this requirement. The evolution of seismic design requirements and the calculations of pipe rupture loads have significantly increased the resultant loads obtained by combining these effects. However, field evaluations of piping at conventional power plants and petrochemical facilities have indicated that ruptures in piping of the type found in nuclear power plants do not occur during severe earthquakes. Therefore, relaxation of these requirements should not affect plant or public safety. The resolution of this task will effect all LWRs.

CONCLUSION

This item is a Regulatory Impact issue.

ITEM 119.2: PIPING DAMPING VALUES

DESCRIPTION

Historical Background

This task combines PRC regulatory recommendation A-2 (modify seismic damping values used in seismic designs) and PRC research recommendation B-3 (complete research on damping tests). It constitutes a two-level approach: a short-term plan and a long-term plan. The resolution could affect all LWRS. The short-term action will rely on a revision to Regulatory Guide 1.84 as the vehicle for

NRC endorsement of ASME Code Case N-411. The long-term action will result in the revision of Regulatory Guide 1.61 and SRP[11] Section 3.9.2 to incorporate, not only ASME Code Case N-411, but also new positions on pipe damping for high-frequency loads and for time-history analyses.

The short-term endorsement of the ASME Code Case N-411 would be restricted to seismic response analysis, but not time-history analysis. The long-term action will result in extensive changes to SRP[11] Section 3.9.2 and to Regulatory Guide 1.61 to provide more comprehensive guidance on pipe damping for both seismic and BWR hydrodynamic loadings. Criteria for other non-seismic dynamic loads could also be addressed in the SRP[11] Section 3.9.2 revision.

Safety Significance

In general, dynamic piping response would be more accurately predicted if higher piping damping values were used than those identified in the current regulatory guide. The use of higher damping values will result in nuclear plant piping systems having significantly less snubbers and supports and an overall better balance of design considering all piping loads. A significant decrease in the number of snubbers and supports will allow better inspection of equipment and components at significantly reduced ORE.

CONCLUSION

This item is a Regulatory Impact issue.

ITEM 119.3: DECOUPLING THE OBE FROM THE SSE

DESCRIPTION

Historical Background

This task corresponds to PRC regulatory recommendation A-3 (decouple OBE from SSE). 10 CFR 100, Appendix A, Section V(a)(2), stipulates: "The maximum vibratory ground acceleration of the OBE shall be at least one-half the maximum vibratory ground acceleration of the SSE." Therefore, the current requirement implies the coupling of the two earthquake design levels: SSE and OBE. In developing the current regulations, it was assumed that the SSE would control the design in nearly all aspects and that the OBE would serve as a separate check of those systems where continued operation was desired at a lower level of ground motion. However, in practice, the assumed load factors, damping, stress levels, and service limits have caused the OBE, rather than the SSE, to control the design for many systems including concrete and steel structures and nuclear piping. In addition, seismic design for OBE accounts for certain safety-related factors such as fatigue and seismic anchor movement that are not considered in the design for the SSE.

Decoupling of the OBE from the SSE or modification of the associated load factors, etc., would impact the design of new plants and would extend well beyond piping considerations. The actions required to resolve this task include: (1) rulemaking to amend and revise Appendix A to 10 CFR 100 to permit decoupling of the OBE and SSE and to incorporate the use of probabilistic methodology in earthquake design; (2) revising and developing Regulatory Guides; (3) updating pertinent sections of the SRP;[11] and (4) advising various code committees to revise appropriate codes and guides to reflect changes in the regulations.

A complete listing of the Regulatory Guides and SRP Sections that may be affected by this task will be identified during the review phase of this task and the related tasks contained in the NRC implementation plan[835] which is of much broader scope.

Safety Significance

There is no technical basis for coupling the OBE with the SSE. Designing the piping systems to the SSE is the primary means of ensuring safety. Additional margin is provided by specifying the OBE and thus the level at which inspections will be required before continued operation would be permitted. The more realistic approach of using specific probabilities (return periods) for OBE and the decoupling of the OBE levels and frequencies from those of the SSE will allow assurance of public safety to be placed on a more rational basis.

CONCLUSION

This item is a Regulatory Impact issue.

ITEM 119.4: BWR PIPING MATERIALS

DESCRIPTION

Historical Background

This task corresponds to the PRC recommendation A-4 to replace regular grade 316SS and 304SS materials in BWR recirculation piping with an alloy resistant to IGSCC. The NRR staff action related to this task involves preparation of Revision 2 to NUREG-0313[750] and evaluation of each licensee's actions in compliance with this revision.

Safety Significance

IGSCC in BWR piping has occurred in a range of piping sizes over the last 25 years and has resulted in major reactor outages. The risk studies reported[611] indicate that pipe failures, even assuming the higher rates due to IGSCC, would not be a major contributor to core-melt and public risk. However, use of materials more resistant to IGSCC should significantly reduce levels of ISI and reactor outage times. Therefore, plant outages and recurring ORE could be significantly reduced by resolution of this task.

CONCLUSION

This item is a Regulatory Impact issue.

ITEM 119.5: LEAK DETECTION REQUIREMENTS

DESCRIPTION

Historical Background

This task corresponds to PRC regulatory recommendation A-6 (leak detection requirements). To accomplish this task, additional data are necessary to further validate and improve existing leak-rate prediction analyses. Of particular interest would be investigation and improvement of local leak detection systems such as acoustic emission monitors or moisture-sensitive tapes. These latter techniques may be important for establishing the validity of leak-before-break at specific locations in certain piping systems. The task requires a combination of two approaches: (1) the surveying of operating plants to determine the adequacy of existing leak detection systems; and (2) completion of the research recommended by the PRC and applying the results of the research to regulatory requirements. Subsequent to the completion of key elements of the research effort, the regulatory actions may include the following:

(1) Identify required TS changes such as: (a) unidentified leakage limits for BWRs and PWRs in the context of locating and detecting leakage from cracks with margin; (b) adequacy of surveillance requirements and calibration of systems; (c) alarms; (d) TS consistency; (e) new systems or different detection system combinations; and (f) forward-fit and backfit considerations.

(2) Revise SRP[11] Section 5.2.5 and Regulatory Guide 1.45.

(3) NUREG-0313,[750] Revision 2.

Resolution of this task may affect all LWRs to varying degrees.

Safety Significance

No direct safety significance can be attributed to this task. However, knowledge of the leak rates associated with various postulated through-wall crack lengths and confidence in the ability to detect leakage in a timely manner are important elements of the leak-before-break concept that eliminates the postulated DEGB.

CONCLUSION

This item is a Regulatory Impact issue.

REFERENCES

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834. Memorandum for H. Denton and R. Minogue from W. Dircks, "Review of NRC Requirements for Nuclear Power Plant Piping," August 1, 1983.

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ISSUE 121: HYDROGEN CONTROL FOR LARGE, DRY PWR CONTAINMENTS

DESCRIPTION

In December 1984, the staff recommended in SECY-83-357B[861] that rulemaking with regard to hydrogen control for LWRs with large, dry containments could be safely deferred due to the greater inherent capability of these containments to accommodate large quantities of hydrogen.

Ongoing NRC experimental and analytical programs are intended to provide data supplementing the experiments being carried out at the Nevada Test Station (NTS), the experience on hydrogen burn during the TMI-2 accident, and earlier hydrogen burn experiments in order to support a final recommendation on whether safe shutdown equipment is likely to survive a hydrogen burn. Experiments are being planned to determine the significance of factors not included in the NTS experiments (e.g., preconditioning of equipment to simulate aging, enclosing equipment in conduits or protective heat shields, energized equipment). Experimental and analytical studies based in part on NTS-generated data will then be used to determine the local environmental stresses on equipment such as the convective and radiant heat flux to be expected in a hydrogen burn.

In addition to the above, the staff intends to explore the possibility of forming local detonable concentrations in large, dry PWRs and the probable consequences regarding containment and equipment survivability. This has received attention from the standpoint of fundamental detonation phenomena; however, the research effort is now being extended to develop the capability for predicting conditions in realistic configurations.

CONCLUSION

After consideration of the safety concerns associated with this issue and the NRC resources that have been expended so far in pursuit of a solution, this issue was given a HIGH priority ranking.

REFERENCE

861. SECY-83-357B, "Status of Hydrogen Control Issue and Rulemaking Recommendations in SECY-83-357A," December 3, 1984.

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13. 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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