Mitigating Systems Performance Index Pilot Working Group Public Meeting December 3, 2003

Ongoing Research Activities

by

D.A. Dube
Office of Nuclear Regulatory Research

Attachment 4

Activities

- Assessing MSPI PRA Adequacy Issues
  - Sensitivity studies of the effect of PRA model differences on MSPI (approximately 50% complete)
  - MSPI pre-implementation checklist (later, prior to first industry workshop)
  - MSPI input error analysis (later)
- Benchmark MSPI, SSU and SDP results for mitigating systems of Pilot Plants (90% complete)
- Evaluating two options to account for the effect of common cause on Fussell-Vesely importance (later)
  - Generic multipliers for FV/UR for each component type based on system configuration
  - Generic additive terms (CDF * FV/UR, i.e. Birnbaum) for each component type based on system configuration

MSPI Sensitivity to PRA Model Differences

- Sensitivity performed two ways
  - Effect on MSPI assuming one failure more than baseline one component at a time
  - Effect on 4^{th} Quarter 2002 results

- All significant PRA model differences grouped into three to seven change sets, FV/UR values regenerated from revised SPAR model, and MSPI requantified

Possible Sensitivity Study Outcomes

- Large impact
  - Factor of 10 or more on MSPI numerical result, and
  - Will change color (e.g. WHITE to GREEN, WHITE to YELLOW, etc.)
- Medium impact
  - Affects first significant figure of MSPI numerical result, and change > 1E-7
  - Possible change in color depending on how close to threshold
- Low or no impact
  - Affects second significant figure (or lower) of MSPI numerical result, or change < 1E-7
  - Unlikely to or will not change color

MSPI Sensitivity Results

- Braidwood MSPI results for HRS are very sensitive to modeling differences (Large effect), especially PORV success criterion and MFW/PCS basic event probabilities.
- Preliminary results for Salem indicate that failures-to-WHITE for AFW TDP FTS, and SWS MOV FTO/C are very sensitive to loss of SWS initiator frequency.
- Preliminary results for Hope Creek indicate that MSPI for HRS and HPI are most sensitive to HPCI, SWS, and CCW basic event probabilities, but effect is Medium.
- Preliminary results for Millstone 2 indicate Large effect of LOCA initiating event frequencies on MSPI results for several mitigating systems.
- Preliminary results for Limerick indicate no Large sensitivities, but most sensitive to AC power and PCS basic event probabilities.

YELLOW

GREEN

MSPI Results for 4th Quarter 2002

Braidwood 1

11/18/2003

System	Plant PRA Model	SPAR Resolution Model	SPAR Rev. 3 Model	SPAR Enhanced Model	SPAR Issue PORVs	SPAR Issue DCP	SPAR Issue LOCAs	SPAR Issue HPI	SPAR Issue HRS	SPAR Issue SWS/CCW	SPAR Issue PCS
EAC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HPI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HRS	2.28E-06	3.02E-06	2.88E-05	2.88E-05	1.35E-05	4.64E-06	2.99E-06	2.24E-06	1.76E-06	3.68E-06	5.78E-06
RHR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SWS/CCW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MSPI Results for 4th Quarter 2002

Braidwood 2

11/18/2003

System	Plant PRA Model	SPAR Resolution Model	SPAR Rev. 3 Model	SPAR Enhanced Model	SPAR Issue PORVs	SPAR Issue DCP	SPAR Issue LOCAs	SPAR Issue HPI	SPAR Issue HRS	SPAR Issue SWS/CCW	SPAR Issue PCS
EAC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HPI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HRS	[redacted]	[redacted]	3.32E-06	3.32E-06	1.78E-06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.17E-06
RHR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SWS/CCW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Braidwood 2 results use the Braidwood 1 SPAR model importances and CDFs with Braidwood 2 failures, demands and operating hours.

GREEN

MSPI Results for 4th Quarter 2002												
Hope Creek												
11/20/2003												
System	**Plant PRA Model**	**SPAR Resolution Model**	**SPAR Rev. 3 Model**	**SPAR Enhanced Model**	**SPAR Issue AC power**	**SPAR Issue LOCAs**	**SPAR Issue HPI**	**SPAR Issue HRS**	**SPAR Issue RHR**	**SPAR Issue SWS/CCW**	**SPAR Issue PCS**	**SPAR Issue Misc**
EAC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HPI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.27E-06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HRS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.07E-06	[redacted]	[redacted]
RHR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SWS/CCW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
The current Revision 3 SPAR model is now the same as the Enhanced SPAR model.												

GREEN

Preliminary Benchmarking of SDP, MSPI, and SSU

- All SDP (N = 1659) and SSU (N = 5157) results for 3.25 years for mitigating systems for all 100+ plants tabulated
- Results further reduced to subset of 20 Pilot Plants
- All 77 failures from 3 years of MSPI Pilot Plant data individually compared to SDP and SSU as appropriate
- Average of 4 non-Green SDP findings per year for mitigating systems related to actual single failure (not degraded or non-conforming condition) for all plants
- Average of 8 new non-Green SSUs per year (0.5% of total SSUs)
- Numerical simulation of MSPI for 20 Pilot Plants indicate 2.5% to 3.5% non-Green, with assumed average duration of 1 to 1.5 years (equates to about 8 to 18 new non-Green MSPIs per year)

Annual non-Green single failure SDPs + SSU	≈	MSPI
12	≈	8 to 18

- Based on extrapolation from Pilot Plant failures, about 120 actual single failures per year within mitigating systems can be expected for all plants (i.e. about 1.2 actual single failures per year per plant).

Evaluation of Pilot Plant Component Failures

<u>Agreement</u>

- 8 failures where MSPI = SSU = SDP = Green
- 28 failures where MSPI = SSU = Green, no SDP findings
- 1 failure where MSPI = SDP = Green, no SSU
- 1 failure where MSPI = White (Green w Frontstop), SSU = Green, no SDP finding

<u>Differences</u>

- 1 case where three failures give MSPI = SSU = White, and SDP = Green for two
- 1 case where four failures give MSPI = White, SSU = Green, and SDP = Green for two
- 1 case where four failures give MSPI = Green, SSU = White, and SDP = Green for one
- 1 case where five failures give MSPI = Green, SSU = White, and SDP = Green for one
- 1 failure where MSPI = Green, SSU = White, no SDP findings
- 1 failure where MSPI = Green, SSU = SDP = White

Notes: MSPI and SSU are quarterly comparisons, whereas SDP is a single event. The failures contributing to the MSPI may have occurred over several quarters. SDP findings taken from inspection reports. For all remaining failures, there was no basis for comparison since there were no SDP findings nor SSUs.

Examples

- Braidwood-1, AFW DDP: 2 FTS & 1 FTR, 2Q2001 to 1Q2002
  MSPI = 2.28E-6 for HRS (White)
  SSU = 2.5% (White)
  SDP = Green per inspection report #2002004

- Palo Verde-2, AFW MDP: 1 FTS, 4Q2000
  MSPI = 3.02 E-6 w/o Frontstop (White), = 4.4E-7 w Frontstop (Green)
  SSU = 0.5% (Green)
  No SDP finding

- Surry-1, EDG: 2 FTS, 1 FTR & 1 FTLR, 3Q2000 to 4Q2002
  MSPI = 3.91E-7 (Green)
  SSU = 3.2% (White), fault exposure hours = 238
  SDP = Green per inspection report #2001007

Summary

- MSPI sensitivity studies indicate a number of PRA modeling differences that could have large effect on MSPI results. An approach to resolve these differences such as the proposed pre-implementation checklist needs to be considered.
- It appears that the total number of non-Green findings per year attributed to mitigating systems would not be significantly changed with MSPI implementation.
- The amount of NRC and perhaps industry resource savings resulting from MSPI implementation owing to the reduction in the number of SDP Phase 3 evaluations appears to be minimal.

SINGLE FAILURES AND CONDITIONS EVALUATED BY SDP FOR ACTION MATRIX INPUT

- Passive failures
- Multiple failures
- Common-mode failures
- Failures that cannot be discovered during normal surveillances
- LERF and external events (requires a Phase 3 SDP analysis for all single failures w/performance deficiencies that have risk significance > than 1 E-7 CDF)

Attachment 5

Attachment 6

DRAFT

Possible Schedule

January 20, 2004	NEI - Draft guidance for Pilot's comments	• 99-02	
Mid February 2004	NRC Go/No-go decision NEI - Develop remaining draft guidance	NRC start reviewing guidance • 93-01 • "MPSI Primer" document • Basis Document	
March 2004	NEI	Finalize guidance documents	Get NRC final comments and write Rev 0
April 2004 (>2 weeks before Workshop)	NEI - Guidance documents to Workshop attendees		NEI repro and get to workshop attendees
May 5, 2004	**Workshop A** (National)	1 ½ day workshop w/NRC to cover MSPI derivation, success criteria, system boundaries, active components – breakout sessions by reactor type led by pilot plants. Homework for next workshop is to develop their scope, active components, FVs. Breakout sessions: PRA; By Type. Activities are: • Basic theory • Step-by-step • Lessons Learned (resources) • Homework • TI • Generic PRA insights	Audience: PRA Licensing Systems Engineering Maintenance Rule NRC DivDirectors, Branch Chiefs, SRAs
May - June	NRC Sr Resident Meeting (Regional)	NRC/NEI provide training on program and TI (who inspects what)	NRC Resident Inspectors
June – August	INPO	Issue rules for sorting historical data EPIX	
August 16, 2004	**Workshop B** (National)	Review homework and get concurrence on scope and components. Breakout by type Presentation on CDE (how to put	Need maximum resident participation attendance

		FVs into CDE etc.) – INPO to provide a "CDE Workshop version" for practice.	
September – October 2004	NRC Residents	NRC conduct TI each plant	
October 2004	INPO	Beta test CDE and get it up and running correctly before start of program. Plants start to enter historical data.	
November 2004	**Workshop C** (National)	Resolve any final issues with scope and components	Any plant (plant personnel and associated NRC personnel) which still has outstanding TI issues.
January 1, 2005	Program Start		
April 21, 2005	1Q05 data submittal	Historical Data and 1Q05 data submittal under new program	

STATUS OF THE SHUTDOWN SDP TOOLS

Marie Pohida
Probabilistic Safety Assessment Branch (SPSB)
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

December 4, 2003

Attachment 7

TIME LINE FOR SDP TOOL DEVELOPMENT

- Inspection Manual Chapter (IMC) 0609 Appendix G , Shutdown Phase 1 SDP tool was released February 2000.
- SPSB is currently responsible for assessing all shutdown performance deficiencies identified from phase 1 tool from Regions.
- SPSB initiated development of PWR/BWR phase 2 shutdown templates to allow SRAs to quantitatively assess shutdown findings.
- operational Support team
  OST conducted four feasibility tests of PWR/BWR phase 2 shutdown templates from March-June 2002.
- Templates presented to SRAs at Spring Counterpart meeting in May 2002.
- In August 2002, Templates sent to SRAs (for draft use only) followed by a tutorial of the tool by SPSB. SRAs worked through a PWR and BWR performance deficiency using tools.

TIME LINE FOR SDP TOOL DEVELOPMENT (continued)

- ❑ On August 15, 2002, PWR SDP tool was used to assess sample problem and compare results with the Surry Shutdown Model (Surry Pilot).

- ❑ On August 22, 2002, Shutdown SDP tools were presented at monthly ROP meeting.

  - ❑ Worked through simple sample problem
  - ❑ Answered questions
  - ❑ Provided 2 sample problems to be analyzed at public workshop

- ❑ On January 22, 2003, SPSB held a public workshop to discuss the phase 2 templates.

- ❑ SPSB concluded that phase 2 templates need a basis document to define the PRA model used to develop the templates.

- ❑ SPSB also concluded that template needs to emphasize that all available systems can be credited to provide shutdown safety functions.

SDP TOOL DEVELOPMENT IN 2003

- In Summer 2003, SPSB developed a basis document for both the PWR and BWR phase 2 templates.

  Explains how precursor events handled
  Provides basis for HEPs (Human Error Probabilities)

- In Summer/ Fall 2003 - SPSB revised all HEPs in the PWR and BWR Template using the recently released draft SPAR-H Methodology (June 2003).

To Complete and Release the Templates

- ❑ SPSB to complete Technical Development by January 31, 200~~3~~4.

- ❑ SPSB to schedule Public Workshop to discuss the Basis Document in Mid-January

- ❑ Templates will be attached to Public Workshop Meeting Notice.

- ❑ SPSB to update Manual Chapter 0609 Appendix G to the enhanced version in Spring 2004.

Appendix H - Shutdown Operations

Marie Pohida
Senior Reliability and Risk Analyst
NRR\DSSA\SPSB
301-415-1846
December 4, 2003

Attachment 8

Applicability of Appendix H

- LERF considered for first 8 days of outage BEFORE cavity filled for refueling (8 days approx. ½ life of I -131).

- Definitions of Plant Operation States in Appendix H same as Appendix G

- Includes findings occurring during POS 1E and POS 2E for BWRs and PWRs within first 8 days of outage

  POS 1 BWR - RHR operating, vessel head is on.
  POS 2 BWR - RHR operating, vessel head is off
  POS 1 PWR - RHR operating, RCS closed
  POS 2 PWR - RHR operating, RCS open

- Definition of Type A and B shutdown findings same as full power.

Summary of Appendix H Shutdown

- If finding occurs before refueling (TW-E) and within 8 days of outage, then:

  Type A findings: Each shutdown core damage scenario Appendix G) is assigned a LERF factor based on containment type and status of containment

  (E.G. intact, open, or de-inerted (BWR Mark 1 and 2s)

Type B findings: Finding assessed a color (using Table 6.2)

Color based on containment type, containment SSCs involved by finding, and mitigation capability (in-depth or minimal)

Color based on Shutdown CDFs from SECY 97-168, Proposed Shutdown Rule (Voluntary Action Case) and LERF factors in Table 5.2 of Appendix H.

Voluntary Initiatives and Their Impact on Appendix H

Industry and NRC Shutdown Guidance

NUMARC 91-06	Maintain Shutdown Safety Functions Decay Heat Removal Inventory Control Power Availability Reactivity Control Containment
GL 88-17	Reduce PWR risk during Reduced Inventory and Midloop Operation 2 sources of level/temp. instrumentation 2 available means of RCS injection Containment Closure capability Procedures for Loss of RHR function

Proposed Shutdown Rule and Its Impact on Appendix H

- In SECY 97-168, the staff requested a proposed rule during cold shutdown and refueling operation.

- Proposed rule required a mitigation capability in the event of loss of operating DHR system.

- To justify the rule, staff prepared a risk analysis considering 3 separate cases:

  - Compliance with current TS - no additional voluntary initiatives
  - Implementation of Industry and NRC guidance (NUMARC 91-06 and GL 88-17) - includes voluntary initiatives
  - Compliance with the proposed Rule - no additional voluntary initiatives

Proposed Shutdown Rule and Its Impact on Appendix H(Continued)

- In SECY 97-168, the Staff concluded that existing level of safety is largely dependent on voluntary actions.
- In response to SECY 97-168, Commission did not authorize rule.
- In response to SECY 97-168, Commission directed staff to inspect shutdown operations to ensure that current level of safety is maintained.
- Commission may take action if any adverse trends are identified.
- Through SDP process, staff is ensuring that key voluntary initiatives such as maintaining a containment closure capability are being maintained.

Summary of Industry Comments to Draft Appendix H

From a PWR

- "Containment closure requirements differ from our legal requirements"

  Response: SRM to SECY 97-168 directed staff to ensure that key voluntary initiatives are being maintained. SDP process not limited to regulatory requirements to assess color of finding. Staff uses available equipment to assess color of finding.

- "Basis for Containment SDP"

  Response: Basis for the Containment SDP is the SRM to SECY 97-168 and SECY 99-007a.

Summary of Industry Comments to Draft Appendix H (continued)

- " Is this a requirement that we need to model LERF for modes 5 and 6"

  Response: There is no requirement for a licensee to model LERF for Modes 5 and 6. However, the staff needs to use the LERF risk metric to assess performance deficiencies at shutdown within first 8 days of the outage.

From BWR:

- "Phase 3 findings will present problems at plants where Level 2 PRA's have not been performed. The document also treats "shutdown states" and most plants have not performed shutdown PRAs."

Response: The staff has previously evaluated over 50 shutdown performance deficiencies through the SDP process, consistent with SRM to SECY 99-007a and the SRM to SECY 97-168.

The staff expects the licensee to maintain a containment closure capability consistent with Industry and NRC guidance.

- "Shutdown LERF does not consider the margin provided in the Time to Boil of BWRs"

Response: Consistent with Note 1 in Table 5.4 and Note 1 in Table 6.3, an intact containment means that containment can be re-closed prior to boiling of RCS inventory. (Applies to BWRs and PWRs).

Summary of Industry Comments to Draft Appendix H (continued)

- "Logic diagrams (e.g. Figure 4.1 and 5.10 have diamond blocks with negative questions"

  Response: Staff will adjust wording to make it clear.

- POS 2 and POS 3 definitions are defined according to whether vessel level is less 23 above the flange. Many BWRs have the actual setpoint at 22' 9".

  Response: The delineation of 23' was based on the BWR/4 STS for the RHR system on high water level and low water level.

Summary of Industry Comments to Draft Appendix H (continued)

- "The igniters are not included in the Maintenance Rule for Shutdown Conditions......since there is no technical specification for the operation of the igniters during shutdown and no shutdown mitigation defense using igniters, this equipment should be removed as a contributor to LERF during shutdown."

  Response: SDP process not limited to regulatory requirements to assess color of finding. Staff uses available equipment to assess color of the finding.

  If unavailability of the igniters results in risk estimates outside the industry risk bands reported in SECY 97-168, the staff will notify the Commission.

Attachment 9

Appendix H

Containment Integrity Significance Determination Process (SDP)

Presentation for
ROP Public Meeting

December 4, 2003

Objectives:

a) To provide a brief overview of the appendix guidance.

b) To respond to received comments.

Background:

Appendix H Covers:

a) Phase 1 and Phase 2 generic step-wise guidance.

b) Covers full power and shutdown operations.

c) Develops a reasonably conservative Large Early Release (LERF) counting rule and associated worksheet.

d) Technical basis attachments to the draft final will be part of the SDP technical basis chapter (IMC 308). (Technical basis information may be needed to comprehend, defend, or justify going to phase 3 assessment in plant-specific cases).

e) Applied examples in attachment 2 of the draft final will be used for training.

Types of Inspection Findings

Appendix H distinguished between two types of Inspection findings namely:

a) Type A Findings

An inspection finding that can influence the likelihood of accidents leading to core damage that are also identified as potential contributor to LERF.

Note: Items screened out based on delta-CDF significance are considered in appendix H.

b) Type B Findings

Degraded conditions affecting containment barrier integrity . (that can potentially increase LERF without affecting CDF)

Table 1A-1 Containment-Related SSCs Considered for LERF Implications

SSC	Comments related to LERF significance
Containment penetration seals - BWR Mark I and II drywell or PWR containment - BWR Mark III wetwell	Failure of penetration seals that form a barrier between the containment and the environment can be important to LERF
Containment isolation valves in lines: - connecting BWR drywell or PWR containment airspace to environment - connecting RCS to environment or open systems outside containment - connected to closed systems inside/outside containment	Large lines connecting containment airspace to environment (e.g., vent/purge) can contribute to LERF. Small lines (< 1-2 inch dia) and lines connecting to closed systems would not generally contribute to LERF. Isolation valves connecting to RCS can contribute to ISLOCA
Main Steam Isolation Valves	Excessive MSIV leakage can contribute to LERF in high pressure accident sequences in Mark I and II plants
BWR drywell/containment sprays	Mark I and II drywell sprays and Mark III containment sprays are important to preventing liner melt-through and mitigating suppression pool bypass
Containment flooding system(s)	Important to preventing liner melt-through in Mark I's
PWR containment sprays and fan coolers	Impact late containment failure and source terms, but not LERF
Hydrogen control system -igniters -air return fans and hydrogen mixing systems	Important to LERF in Mark III and ice condenser plants Not essential to hydrogen control if igniters are available
Suppression pool (SP) systems -components important to SP integrity/scrubbing (e.g., vacuum breakers) -suppression pool cooling	Important to LERF in all BWR plants Impacts late containment failure but not LERF
Ice condenser system - ice condenser doors and ice bed - air return fans - ice mass air return fans - foreign objects in ice compartment	Significant flow blockage can be important to LERF Not important to LERF (similar to containment sprays) Deviations in weight of ice not important to LERF Not important to LERF (unless CDF is affected)
Filtration systems - Standby Gas Treatment System - control room ventilation	Not important to LERF due to unavailability in dominant sequences (e.g., SBO), plugging from high aerosol loadings in severe accident, and other considerations
Spent fuel assemblies (individual) - fuel handling accidents within pool - fuel handling accidents outside pool	Not important to LERF due to small fission product inventory contained in single fuel bundle. Scrubbing by water in the spent fuel pool further reduces releases.

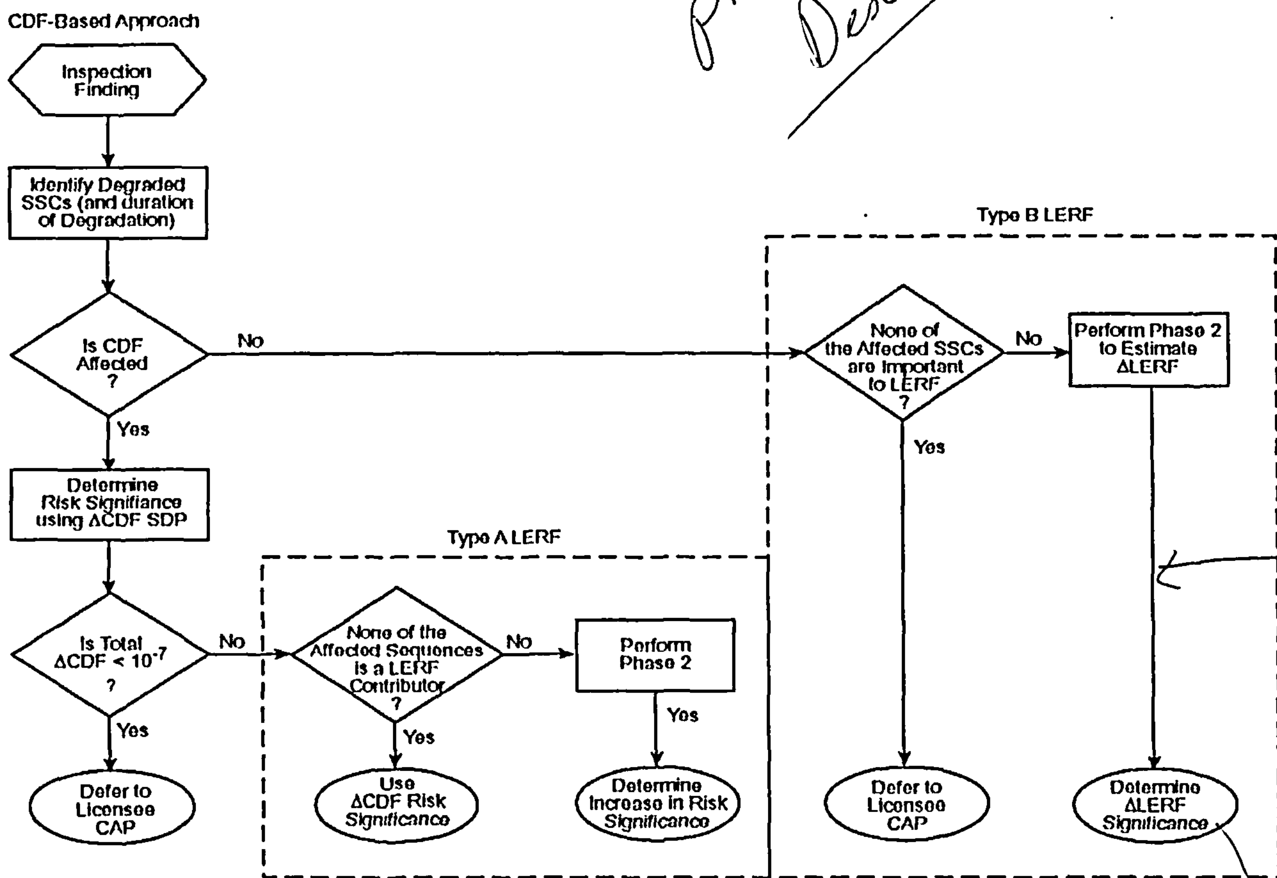
RISK SIGNIFICANCE BASED ON ΔLERF vs. ΔCDF

Table 1.1 Risk Significance Based on ΔLERF vs ΔCDF

Frequency Range/ry	SDP Based on ΔCDF	SDP Based on ΔLERF
$\geq 10^{-4}$	Red	Red
$< 10^{-4} - 10^{-5}$	Yellow	Red
$< 10^{-5} - 10^{-6}$	White	Yellow
$< 10^{-6} - 10^{-7}$	Green	White
$<10^{-7}$	Green	Green

- Risk characterization based on LERF SDP is one order of magnitude higher than CDF SDP

Phase II Description



consider appropriate licensee input?

phase 3

Figure 4.1: LERF-based Significance Determination Process (Phase II)

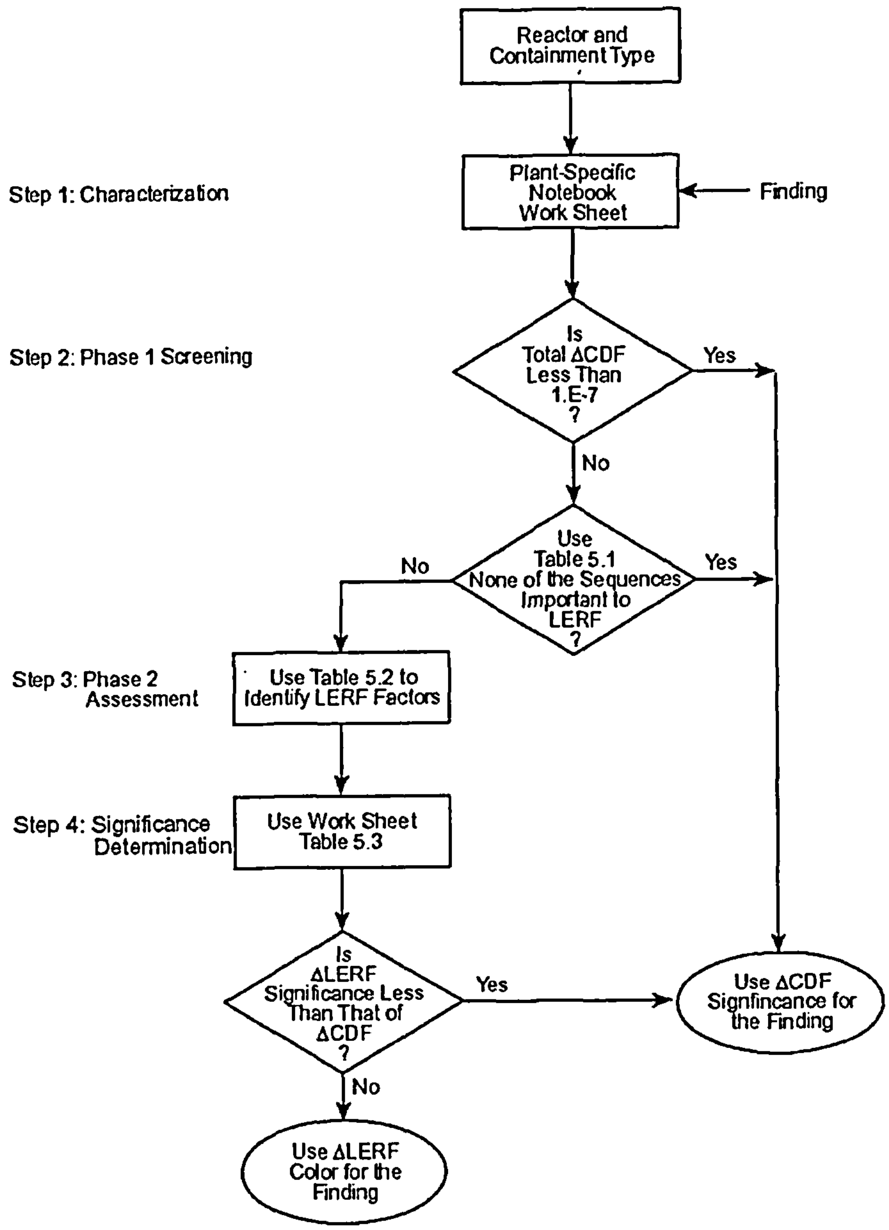


Figure 5.1: Road Map for LERF-based Risk Significance Evaluation for Type A Findings at Fullpower

Table 5.1 Phase 1 Screening-Type A Findings at Full Power							
Reactor Type	Containment Type	Attributes of Accident Sequence Related to Finding					
		ISLOCA	SGTR	ATWS	SBO (Note 1)	High RCS Pressure (Note 2)	All Others
BWR	Mark I	Perform Phase 2	Not Applicable	Perform Phase 2	Perform Phase 2	Perform Phase 2	Note 3
BWR	Mark II	Perform Phase 2	Not Applicable	Perform Phase 2	Perform Phase 2	Perform Phase 2	Screen Out (Note 4)
BWR	Mark III	Perform Phase 2	Not Applicable	Screen Out (Note 4)	Perform Phase 2	Perform Phase 2	Screen Out (Note 4)
PWR	Large Dry and Sub-Atmospheric	Perform Phase 2	Perform Phase 2	Screen Out (Note 4)	Screen Out (Note 4)	Screen Out (Note 4)	Screen Out (Note 4)
PWR	Ice Condenser	Perform Phase 2	Perform Phase 2	Screen Out (Note 4)	Perform Phase 2	Screen Out (Note 4)	Screen Out (Note 4)

Note 1: SBO is defined as a LOOP sequence with loss of emergency AC and failure to recover AC power.

Note 2: High pressure is defined as greater than 250psi at the time of reactor vessel breach. Transients and small break LOCAs (smaller than about 2-inch equivalent break size in BWRs and 0.75 - 1 inch in PWRs) will usually result in pressures in the RCS greater than 250psi at the time of reactor vessel melt-through in the absence of manual depressurization.

Note 3: A phase 2 assessment should be performed for any sequences that are expected to proceed to reactor vessel breach into a dry reactor cavity. Transients with successful RCS depressurization but failure of drywell sprays and containment flooding should be assessed. Sequences involving LOCAs in the drywell or drywell spray operation would be excluded from analysis since they result in a flooded drywell floor.

Note 4: Screen out means that the accident sequence related to the finding is not significant to LERF.

Table 5.2 Phase 2 Assessment Factors -Type A Findings at Full Power							
Reactor Type	Containment Type	Attributes of Accident Sequence Related to Finding					
		ISLOCA	SGTR	ATWS	SBO (Note 1)	High RCS Pressure (Note 2)	Low RCS Pressure (Note 2)
BWR	Mark I	1.0	Not Applicable	0.3	(Note 3)	0.6 If drywell is Flooded 1.0 If drywell is Dry	<0.1 If drywell is Flooded 1.0 If drywell is Dry
BWR	Mark II	1.0	Not Applicable	0.4	(Note 4)	0.3	Screened Out in Phase 1
BWR	Mark III	1.0	Not Applicable	Screened Out in Phase 1	0.2	0.2	Screened Out in Phase 1
PWR	Large Dry and Sub-Atmospheric	1.0	1.0	Screened Out in Phase 1	Screened Out in Phase 1	Screened Out in Phase 1	Screened Out in Phase 1
PWR	Ice Condenser	1.0	1.0	Screened Out in Phase 1	1.0	Screened Out in Phase 1	Screened Out in Phase 1

Note 1: SBO is defined as a LOOP sequence with loss of emergency AC and failure to recover AC power.

Note 2: High pressure is defined as greater than 250psi at the time of reactor vessel breach. Transients and small break LOCAs (smaller than about 2-inch equivalent break size in BWRs and 0.75 - 1 inch in PWRs) will usually result in pressures in the RCS greater than 250psi at the time of reactor vessel melt-through in the absence of manual depressurization.

Note 3: If the RCS is at high pressure during the SBO then the Factors for the high pressure column apply. If the RCS is at low pressure during the SBO then the Factors for the low pressure column apply.

Note 4: If the RCS is at high pressure during the SBO then the Factor is 0.3. If the RCS is at low pressure during the SBO then the Finding can be screened out.

Table 5.3: Worksheet for ΔLERF

(1) Sequences	(2) ΔCDF Score x	(3) Sequence Attributes	(4) LERF Factor (Table 5.2 for full power, Table 5.4 for low power) f	(5) ΔLERF Score f* E-x
			Total ΔLERF Score'	

ΔLERF=3.3* Total ΔLERF Score

A.1 Examples for Illustrating the Type A LERF at Full Power

1. Finding Related to HPCI System

The first example selected below for illustrating use of the LERF guidance is based on findings related to an unavailability of the High Pressure Core Injection (HPCI) system at a BWR Mark I plant for greater than 30 days. The finding had been processed through the plant-specific notebook as a white finding.

Step 1: Finding Characterization

The sequences affected by the finding are identified in the plant-specific notebook worksheets. Attached here, as an example are the SDP worksheets, associated with the finding under consideration. The ΔCDF scores are shown for those sequences.

Step 2: Accident Sequence Screening

Using Table 5.1 those sequences that have the characteristics of a LERF contributor are identified (with a check mark): Of the two sequences from the TPCS worksheet, (first two pages of the worksheets) only sequence 4 is retained, since there has been a faiure to depressurize the reactor and RCS is assumed to be at high pressure at core melt and at vessel breach. Sequence 3 (in the SDP work sheet) is one in which the reactor has been successfully depressurized, and therefore the RCS is at low pressure at the time of vessel breach.

The sequences that are LERF contributors are documented in Table A.1-1 (based on Table 5.3). (The MLOCA sequence is on the boundary of a medium to small LOCA so the RCS pressure was conservatively assumed to be high in this case). Only the sequences that have a score of 8 or greater (i.e., a ΔCDF of 1E-8) are shown. The characteristics that lead them to be classified as LERF contributors are also documented, based on an interpretation of the accident sequences.

Step3: Phase 2 Assessment

Step 3.1 LERF Factor Determination

The LERF factors for each of the sequences is taken from Table 5.2 for the appropriate sequence characteristics.

Step 3.2 ΔLERF Evaluation

The ΔLERF score for each sequence is obtained by multiplying the ΔCDF score by the factor and entered in column (5).

Step 4: LERF Significance

The overall risk significance (yellow) of the finding based on LERF is determined by summing the scores for each sequence, and multiplying by 3.3.

Table A.1-1: LERF Worksheet

Finding: HPCI

(1) Sequences	(2) ΔCDF Score X	(3) Sequence Attributes	(4) LERF Factor Table 5.2 f	(5) ΔLERF Score f*E-X
TPCS - IC - HPI - DEP 1 + 2 + 0 + 3	6	High RCS Pressure Drywell Floor: Dry	1.0	1.E-6
LOSW - IC - HPI - DEP 3 + 2 + 0 + 3	8	High RCS Pressure Dry Floor: Dry	1.0	1.E-8
LOIA - IC - HPI - DEP 2 + 2 + 0 + 3	7	High RCS Pressure Flooded DryWell floor	0.6	0.6E-7
LAC - IC - HPI - DEP 3 + 2 + 0 + 3	8	High RCS Pressure Dry DryWellFloor	1.0	1.E-8
MLOCA HPI - DEP 4 + 0 + 2	6	High RCS Pressure Flooded DryWell Floor	0.6	0.6E-6
LOOP - IC - HPI - DEP 2 + 2 + 0 + 3	7	High RCS Pressure Dry DryWell Floor	1.0	1.E-7
LOOP - EAC-HPI 2 + 5 + 0	7	High RCS Pressure Dry DryWell Floor	1.0	1.E-7
			Total ΔLERF Score	1.88E-6

ΔLERF=3.3 x Total ΔLERF Score=6.2E-6

2. Finding Related to SSW Pump

The second example is a finding related to a Standby Service Water (SSW) pump at, a BWR with a Mark III containment. Risk significance evaluation followed steps similar to those used in the last example. Data taken from the SDP plant notebook indicate that the finding affects many accident sequences including transients related to loss of power conversion system (TPCS), loss of a DC bus (TDC2), loss of plant service water (TPSW), inadvertent opening of a relief valve (IORV), loss of offsite power (LOOP) sequences and loss of AC (LAC) bus sequences. The CDF score of the finding for each of the sequences down to a score of 8 (i.e., a ΔCDF of 1E-8) are shown in Table A-1-2 below that is taken from the plant-specific notebook.

For a Mark III plant, the attribute of the CDF accident sequence types (refer to Table 5.2 in text) that impacts LERF is whether the RCS is at high pressure and/or whether it is a SBO sequence (i.e., igniters not operating). All the sequences shown in Table II.2 above have been judged to have high RCS pressure and two in addition are SBO sequences.

The overall risk significance of the finding is determined to be white.

Note that the last 3 sequences in Table A-1-2 were judged to lead to late containment failure. These sequences involve failure of containment heat removal and/or depressurization, both occurring late in the accident sequence. For this reason, they were excluded from contributing to LERF by setting the LERF factor (f) equal to zero.

Table A-1-2: LERF Worksheet

Finding: BWR MK III/SSW

(1) Sequences	(2) ΔCDF Score X	(3) Sequence Attributes	(4) LERF Factor Table 5.2 f	(5) ΔLERF Score f*E-X
TPC-HPCS-RCIC-DEP 1 + 2 + 1 + 3	7	High RCS Pressure	0.2	0.2E-7
IORV-PCS-HPCS-LT 2 + 2 + 2 + 2	8	High RCS Pressure	0.2	0.2E-8
LOOP-EAC 1&2-REC1-HPCS-DGX-RCIC 2 + 2 + 0 + 2 + 1 + 1	8	High RCS Pressure	0.2	0.2E-8
LOOP-EAC 1&2-EDG3-REC10 2 + 2 + 1 + 2	7	High RCS Pressure SBO Sequence	0.2	0.2E-7
LOOP-EAC1&2-REC1-EDG3-RCIC 2 + 2 + 0 + 1 + 1	6	High RCS Pressure SBO Sequence	0.2	0.2E-6
TDC2-HPCS-CHR-LDEP 3 + 2 + 0 + 2	7	High RCS Pressure, Containment Heat Removal Failure, Late Containment Failure	0	-
LAC2-HPCS-CHR-LDEP 3 + 2 + 0 + 2	7	High RCS Pressure Late Containment Failure	0	-
TPSW-SSW-LDEP 3 + 2 + 2	7	High RCS Pressure, Late Depressurization Failure Late Containment Failure	0	-
		Total ΔLERF Score		2.44E-7

ΔLERF=3.3x Total ΔLERF Score ≈ 8.2 E7

Therefore the overall color of the finding based on Table 1.1 is White for this finding.

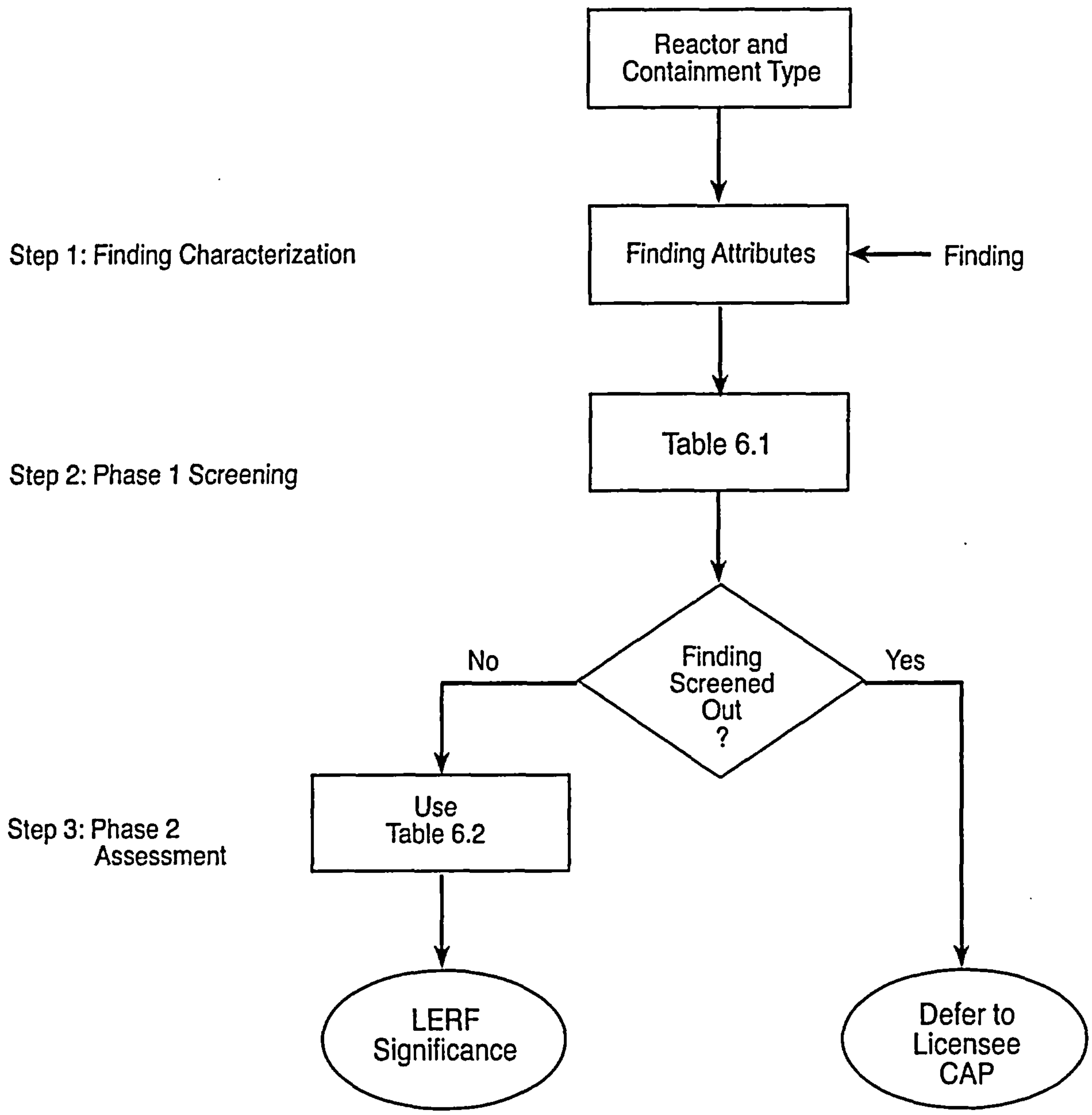


Figure 6.1: Road Map for LERF-based Risk Significance for Evaluation Type B Findings at Fullpower

Table 6.1 SSCs Relevant to LERF Determination							
Reactor Type	Containment Type	SSC Affected by Finding					
		Containment Penetration Seals, Isolation Valves, Vent and Purge Systems	Suppression Pool Integrity	MSIV Leakage	Drywell/ containment Sprays	Igniters	Ice Condenser Integrity
BWR	Mark I	Perform Phase 2	Perform Phase 2	Perform Phase 2	Perform Phase 2	Not Applicable	Not Applicable
BWR	Mark II	Perform Phase 2	Perform Phase 2	Perform Phase 2	Perform Phase 2	Not Applicable	Not Applicable
BWR	Mark III	Perform Phase 2	Perform Phase 2	Not Applicable	Perform Phase 2	Perform Phase 2	Not Applicable
PWR	Large Dry and Sub-Atmospheric	Perform Phase 2	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
PWR	Ice Condenser	Perform Phase 2	Not Applicable	Not Applicable	Not Applicable	Perform Phase 2	Perform Phase 2

Table 6.2 Phase 2 Risk Significance -Type B Findings at Full Power					
Reactor Type	Containment Type	Finding	Risk Significance		
			> 30 days	30 - 3 days	< 3 days
BWR	Mark I and Mark II	Leakage from drywell to environment >100 % containment volume/day through containment penetration seals, isolation valves or vent and purge systems	Yellow	White	Green
		Failure of systems/components critical to suppression pool integrity/scrubbing (vacuum breakers or other bypass mechanisms)	Yellow	White	Green
		Main steam isolation valve leakage >10,000 scfh through the best-sealing valve in any steam line	Yellow	White	Green
	Mark I	Drywell sprays unavailable	Yellow	White	Green
	Mark II	Drywell sprays unavailable	White	Green	Green
BWR	Mark III	Leakage from wetwell to environment >1,000 % containment volume/day through containment penetration seals, isolation valves or vent and purge systems	White	Green	Green
		Failure of systems/components critical to suppression pool integrity/scrubbing (vacuum breakers or other bypass mechanisms)	Yellow	White	Green
		Failure of multiple igniters such that coverage is lost in two adjacent compartments	White	Green	Green
		Containment sprays unavailable	White	Green	Green
PWR	Large Dry and Sub-Atmospheric	Leakage from containment to environment >100 % containment volume/day through containment penetration seals, isolation valves or vent and purge systems	Red	Yellow	White
PWR	Ice Condenser	Leakage from containment to environment >100 % containment volume/day through containment penetration seals, isolation valves or vent and purge systems	Red	Yellow	White
		Blockage of more than 15% of the flow passage into or through the ice bed	Red	Yellow	White
		Failure of multiple igniters such that coverage is lost in two adjacent compartments	Red	Yellow	White

Conclusion

1) Developmental work is complete.

2) Staff training is planned.

3) Public workshop is under consideration.

Response to Comments Received on
10/10/03

COMMENT:
1) The use of a CDF and LERF mix as criteria for determining the significance of Phase 3 containment inspection findings is a new approach, which may present problems not yet anticipated. Phase 3 findings (which require an input by an NRC risk analyst using the SPAR model)...........

RESPONSE:
-Appendix H has guidance for Phase 1 (Screening) and Phase 2 (approximate analysis) only. It does not involve the use of SPAR models. This guidance is meant for use by the staff for evaluation of inspection finding significance (color), and for discussion with the licensee staff. In case of disagreement, the finding is deferred to phase 3 evaluation.
An inspection finding significance is not determined by a CDF and LERF mix, but rather by comparing the CDF and LERF colors, the higher color determines the finding significance.

COMMENT:
2) Some of the logic diagrams(e.g. Figures 4.1 and 5.1) have diamond blocks with negative questions-This can be confusing.......

RESPONSE:
-Staff will consider changes in the forthcoming revision of the appendix.

JUSTIFICATION OF THE 3.3 FACTOR
EXAMPLE

A- An inspection finding was evaluated using the plant-specific Notebook .

B- A number of CDF sequences were identified for the finding in the plant-specific notebook. Out of these sequences 3 were found to impact LERF.

C- Scores for these sequences are 7, 7, and 7 in the notebook worksheet. A score of 7 means the sequence frequency is in the range of 1. E-7 to 9.9 E-7.
For this reason the value of 3.3 E-7 was adopted for sequences with a score of 7. Consequently, three sequences with the same color are equivalent to a sequence of higher color. (i.e. three greens are equivalent to a white)

*Please note that SDP phase 2 assessment is an approximate evaluation.

D-Using the guidance Table 5.2, the three sequences have LERF factors of 0.1, 1.0, and 0.4 respectively.

Delta LERF = 0.1x 3.3xE-7 + 1.0 x 3.3 E-7 + 0.4 x 3.3 E-7

= 3.3 [0.1 E-7 +1.0 E-7 +0.4 E-7]
=4.9 E-7

LERF significance is White

Attachment 10

35.7 (the text in **BOLD** is what has been added)

Response:
Yes. Page 95 line 19-23 of NEI 99-02 will be modified as follows:
The testing of the public alert and notification system shall meet the requirements of the licensee's FEMA approved Alert and Notification System (ANS) design report and supporting FEMA approval letter. Changes to the activation and/or testing methodology ***shall receive FEMA approval prior to implementation*** *and shall be noted in the licensee's quarterly PI report in the comment section*. Siren systems may be designed with equipment redundancy, *multiple signals* or feedback capability. It may be possible for sirens to be activated from multiple control stations *or signals*. If the use of redundant control stations *or multiple signals* is in approved procedures and is part of the actual system activation process, then activation from either control station *or any signal* should be considered a success.

Note: If prior to this FAQ response, a plant changed their testing methodology without prior FEMA approval, it is not necessary to recalculate their past PI data from the time of the change, so long as they subsequently obtain FEMA approval. However, those plants still need to update the affected PI data report by noting the change in the comment section.

35.8

NRC PROPOSED RESPONSE:
No. NEI 99-02 guidance states that "the staffing must be considered in advance and an operator identified to take the appropriate prompt response for the testing configuration independent of other control room actions that may be required." Reliance on emergency operating procedures to direct an operator to restore the required function does not meet the intent of this guidance.

36.3

NRC PROPOSED RESPONSE:
Yes. For this occurrence only (and only on a one-time basis), Sequoyah may treat the notifications as accurate as long as either "actual" or "drill" was selected (completing all the appropriate blocks on the notification form).

For all PI submittals (for all plants) for the second quarter of 2004 and beyond, all notification forms must be marked consistently, either "drill" or "actual," in accordance with the requirements of the licensee's emergency preparedness program.

TempNo.	PI	Question/Response	Status	Plant/ Co.
27.3	IE02	Question: Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal Background Information: On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level. The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR." The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required). Verify the following: TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum No TDRFP trip signals are present Depress TDRFP Turbine RESET pushbutton and observe the following Turbine RESET light Illuminates TDRFP High Pressure and Low Pressure Stop Valves OPEN PUSH M/A increase pushbutton on the Manual/Automatic Controller station Should this be considered a scram with the loss of normal heat removal? Proposed Answer: The ROP working group is currently working to prepare a response.	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed	LaSalle
28.3	IE02	Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated. Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

Attachment 11

TempNo.	PI	Question/Response	Status	Plant/ Co.
		the rapid sequence of events. As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump (MFP)) until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation. Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal. Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal? Response: The ROP working group is currently working to prepare a response.		
30.8	IE02	Question: Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal? Response: The ROP working group is currently working to prepare a response.	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
32.3a	IE02	Question: An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

TempNo.	PI	Question/Response	Status	Plant/ Co.
		trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam supply. When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip. It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue. The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs		

TempNo.	PI	Question/Response	Status	Plant/ Co.
		prior to recommencing the startup. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator? Response: Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves. During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.		
34.6	IE02	Question: Should the following event be counted as a scram with loss of normal heat removal? STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the main turbine. Approximately 17 minutes after the Unit was manually tripped main condenser vacuum was broken at the discretion of the Shift Supervisor to assist in slowing the turbine. Plant conditions were stabilized using Auxiliary Feedwater and Steam Generator Power Operated Relief Valves. Main Feedwater remained available via the electric motor driven Startup Feedwater pump. Main steam headers remained available to provide cooling via the steam dump valves. At any time vacuum could have been reestablished without diagnoses or repair using established operating procedures until after completion of the scram response procedures. Scrams with a Loss of Normal Heat Removal performance indicator is defined as *"The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems."* This indicator states that a loss of normal heat removal has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of the main steam isolation valves or loss of turbine bypass capability. The determining factor for this indicator is whether or not the normal heat removal path is available, not whether the operators choose to use that path or some other path. The STP plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps are then designed to start on low steam generator levels. This is expected following normal operation above low power levels and in turn provides the normal heat removal.	3/20 Introduced 3/20 Discussed 6/18 Discussed; Question to be revised to reflect discussion 7/24 Discussed	STP

TempNo.	PI	Question/Response	Status	Plant/ Co.
		This design functioned as expected on December 15, 2002 when the reactor was manually tripped due to high turbine vibration. Normal plant operating procedures 0POP03-ZG-0006 (Plant Shutdown from 100% to Hot Standby) and 0POP03-ZG-0001 (Plant Heatup) state if Auxiliary Feedwater is being used to feed the steam generators than the preferred method of steaming is through the steam generator power operated relief valves. This can be found in steps 7.4 and 7.5 of 0POP03-ZG-0001 and steps 6.6.5 and 6.6.10 of 0POP03-ZG-0006. The note prior to 6.6.10 states *"the preferred method for controlling SG steaming rates while feeding with AFW is with the SG PORVs"*. The normal heat removal path as defined in NEI 99-02 Revision 2 was in service and functioning properly for seventeen minutes after the manual reactor trip and would have continued to function had not the shift supervisor voluntarily broke condenser vacuum and closed the MSIV's. Interviews with the shift supervisor showed that the decision to break vacuum was two part. 1) Based on experience and reports from the field it was known that vacuum would need to be broken to support the maintenance state required for the main turbine and at a minimum to support timely inspection. 2)This would assist in slowing the turbine. The decision to break vacuum was not based solely on mitigating an off-normal condition or for the safety of personnel or equipment. Because Auxiliary Feedwater system had actuated and was in service as expected, the decision was made to use Auxiliary Feedwater and steam through the SG PORVs. As stated earlier, this is the preferred method of heat removal if the decision to use Auxiliary Feedwater is employed as supported by the normal operating procedures while the plant is in Mode 3. Main feedwater remained available via the electric motor driven Startup Feedwater pump and the main steam headers remained available to provide cooling via the steam dump valves if required. Discussion with the shift supervisor showed he was confident that at any time vacuum could have been readily recovered from the control room without the need for diagnoses or repair using established operating procedures if the need arose. An outside action would be required in drawing vacuum in that a Condenser Air Removal pump would require starting locally in the TGB. This is a simplistic, proceduralized and commonly performed evolution. Personnel are fully confident this would have been performed without incident if required. Closing the MSIVs and breaking vacuum as quickly as possible is not uncommon at STP. For a normal planned shutdown MSIVs are closed and vacuum broken within four to six hours typically to support required maintenance in the secondary. If maintenance in the secondary is known to be critical path than vacuum has been broken as early as three hours and fifteen minutes following opening of the main generator breaker. The only reason that vacuum is not broken sooner is because in most cases it is needed to support chemistry testing. By limiting the flow path as described in NEI 99-02 for normal heat removal there is undue burden being placed on the utility. Only recognizing this one specific flow path reduces operational flexibility and penalizes utilities for imparting conservative decision making. Conditions are established immediately following a reactor trip (100% to Mode 3) that can be sustained indefinitely using Auxiliary Feedwater and steaming through the steam generator PORVs. This fact is again supported in the stations Plant Shutdown from 100% to Hotstandby and Plant Heatup normal operating procedures. The cause of a trip, the intended forced outage work scope, or outage duration varies and inevitably will factor into which		

TempNo.	PI	Question/Response	Status	Plant/ Co.
		method of normal long term heat removal is best for the station to employ shortly following a trip. Response: The ROP working group is currently working to prepare a response. Licensee Proposed Response: NO. Since vacuum was secured at the discretion of the Shift Supervisor and could have been restored using existing normally performed operating procedures, the function meets the intention of being available but not used.		
35.6	MS01-MS04	Question: At Waterford-3, the essential chiller is a continuously operating support system for the High Pressure Injection, Heat Removal, Residual Heat Removal , and Emergency AC Power mitigating systems. The function of the Chilled Water System is to provide room cooling to support operation of these systems and other key plant equipment. As such, chiller unavailability should cascade upon the mitigating systems, resulting in mitigating system unavailability. The Plant has established through documented engineering analysis that the functional capability of those mitigating systems is not affected by an interruption of the essential chiller function for a two hour period. The two hour period is not dependent on any operator actions; the time period is based upon the most limiting design temperature for components in the systems in a design basis condition. The mitigating systems are inoperable from a loss of chiller function as soon as chiller function is lost. However, the study establishes that the mitigating systems are available, at least for the first two hours of chiller unavailability. The practice at the plant is that for a loss of chiller function of less than two hours, no unavailability is counted for the mitigating systems. For a loss of chiller function of more than two hours, the counted unavailability time for the mitigating systems is the total chiller unavailability time minus two hours. Is the use of an engineering evaluation to exclude the initial two hour period of unavailable hours as described above consistent with the guidance presented in NEI 99-02, specifically, page 36 lines 14-22? Proposed answer: No. As a general rule, if a support system is not capable of providing its support function to one or more monitored systems, then the monitored systems incur unavailable hours. However, since support systems are not held to the same standards as the monitored systems, in certain specific cases somewhat more credit for operator recovery actions can be allowed for those support systems. Each case is evaluated on its own merits. The two situations where this provision has been approved are documented in FAQs 301 and 302. Guidance is provided in the responses to these two FAQs on the requirements for approval. Note that there must be a specific failure mode identified in order to address these requirements. In both cases where this provision was approved, no diagnosis was required since the impact on the monitored system was obvious, as were the corrective actions - add inventory to, in one case, a diesel generator day tank, and in the other case, to a cooling water surge tank. See FAQ 289 for an example of a situation that was not allowed by the guidance. The guidance was <u>never</u> intended to allow an open-ended exclusion from counting unavailable hours of the monitored system for <u>any</u> failure of a support system, as this FAQ requests. Neither is it the intent of the guidance to allow a support system to be out for <u>any</u> length of time and only count unavailable time against the monitored system after two hours have elapsed, as the FAQ requests. In addition, the NRC	8/21 Introduced 9/25 Discussed. 10/23 Tentative Approval. withdrawn	Waterford 3

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		does not encourage licensees to develop, nor does the NRC wish to review, detailed analyses to demonstrate that a monitored system will function for some period of time with a support system out of service. In the two approved cases, the analyses were simple, as described in the responses..		
35.7	EP03	Question: Can the licensee modify the ANS testing methodology when calculating the site value for this indicator? Response: Yes. Page 95 line 19-23 of NEI 99-02 will be modified as follows: *__The testing of the public alert and notification system shall meet the requirements of the licensee's FEMA approved Alert and Notification System (ANS) design report and supporting FEMA approval letter. Changes to the activation and/or testing methodology shall be noted in the licensee's quarterly PI report in the comment section__* Siren systems may be designed with equipment redundancy, *__multiple signals__* or feedback capability. It may be possible for sirens to be activated from multiple control stations *__or signals__*. If the use of redundant control stations *__or multiple signals__* is in approved procedures and is part of the actual system activation process, then activation from either control station *__or any signal__* should be considered a success. Note: If prior to this FAQ response, a plant changed their testing methodology without prior FEMA approval, it is not necessary to recalculate their past PI data from the time of the change, so long as they subsequently obtain FEMA approval. However, those plants still need to update the affected PI data report by noting the change in the comment section.	8/21 Introduced 9/25 Tentative Approval. The response will be modified to state that the methodology may be changed once a 50.54 (q) has been completed and a letter sent to FEMA requesting the change. 10/23 Modification proposed 9/25 deleted. Tentative Approval	Generic
35.8	MS03	Question: NEI 99-02 states that Planned Unavailable Hours include testing, unless the "function can be promptly restored … by an operator in the control room". The guideline further states that "restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair". "The intent … is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions". In the following scenario, a pump with an auto start feature is placed in "pull-to-lock" for performance of a calibration procedure on a recirculation valve flow transmitter. The pump would only be required to operate during an event requiring use of the Emergency Operating Procedures and instructions to verify pump operability are contained within the EOPs. EOP instructions vary depending on the situation. For example, if a Reactor Trip and Safety Injection occurred, step 9 of E-0 (Reactor Trip or Safety Injection) directs the operator to "Verify Automatic Actions by performing Attachment 1-K (Verification of Automatic Actions) when time permits". Step 2 of Attachment 1-K verifies the status of the pump. This attachment would be performed for all situations, except when a Safety Injection is not required. If a Safety Injection were not required, restoration of the pump would be performed in step 6 of ES-0.1 (Reactor Trip Response). In each case, the specific EOP steps which verify automatic actions are performed after completion of the EOP Immediate Actions. This may take 1 to 2 minutes. The NRC Resident inspectors questioned whether performance of this restoration action (1 to 2 minutes into an event response -period of elevated intensity and probability of human error), meets the intent of NEI 99-02 regarding "virtually certain of success". The licensee believes that in this situation the NEI guidance can be applied since the function can be promptly restored by an operator in the control room and that additional specific written	9/25 Introduced 10/23 Discussed	Beaver Valley

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		instructions to verify pump operability would not be appropriate since the action would be performed in accordance with the EOPs in a pre-determined sequence. In addition, the station conduct of operations procedure, which governs operator performance at all times, specifies "anytime valid plant conditions indicate a need for...Safety System actuation, and the actuation fails to automatically occur, the operator is required to manually initiate the protective action" In this specific case, the control room operator was pre-briefed on the manual pump restoration task during the pre-evolution (transmitter calibration) briefing. Restoration of the pump is a single action (i.e. remove the pump from pull-to-lock). In this example, can the manual operator action be credited in place of the automatic pump start function for continued pump availability?		
		Response:		
36.1	IE02	Question: With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIV's to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam). At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig. Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low. Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser. As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump. The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event. Does this scram constitute a scram with a loss of normal heat removal?	9/25 Introduced and discussed	Quad Cities

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		Response: No. The normal heat removal path was not lost even though the MSIVs were manually closed to control cooldown rate. There was no leak downstream of the MSIVs, and reopening the MSIVs would not have introduced further complications to the event. The normal heat removal path was purposefully and temporarily isolated to address the cooldown rate, only. Reopening the normal heat removal path was always available at the discretion of the control room operator and would not have involved any diagnosis or repair. Further supporting information: The clarifying notes for this indicator state: "*Loss of normal heat removal path* means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path." In this case, the operator did not choose to use the path through the MSIVs, even though the normal heat removal path was available. The clarifying notes for this indicator also state: "*Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair." In this case, the closing of the MSIVs was performed solely to control reactor cooldown rate. It was not performed to isolate a steam leak. There was no diagnosis or repair involved in this event. The MSIVs could have been reopened following normal plant procedures		
36.2	IE02	Question: Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation? <u>Description of Event:</u> At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours. At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel High Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV).Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored. At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including:	9/25 Introduced and discussed	Peach Bottom

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		stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps. **Problem Assessment:** It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs. Reopening of the MSIVs was: • easily facilitated by restarting Reactor Building ventilation, • completed from the control room using normal operating procedures • without the need of diagnosis or repair Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. <u>Discussion of specific aspects of the event:</u> Was the recognition of the condition from the Control Room? ▪ Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room. Does it require diagnosis or was it an alarm? ▪ The event is annunciated in the control room as described previously. Is it a design issue? ▪ Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3. Are actions virtually certain to be successful? ▪ The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required. Are operator actions proceduralized? ▪ The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room.		

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		How does Training address operator actions? ▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training. Are stressful or chaotic conditions during or following an accident expected to be present? • As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions Response: The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.		
36.3	EP01	Question:: In April 2003, Sequoyah Operations decided to change from marking "Drill" to marking "Actual" on the notification forms used in LOR simulator sessions to enhance realism. Emergency Preparedness was unaware of the policy change at the time since only Annual License Exam simulator sessions contribute to DEP at Sequoyah. A LOR trainee questioned the use of "actual" in mid May 2003 and this question was forwarded to Emergency Preparedness for resolution. EP reevaluated the policy of using "Actual" based on the recent Palisades OE and FAQ 338. Sequoyah decided to change its practice back to marking the notification forms as "Drill" during LOR Training as of June 2003. The expectation of how to mark notification forms during LOR simulator training was reviewed with the personnel but notification opportunities in the September NRC Exams were subsequently inconsistently marked as either "drill" or "actual" consistent with the trainee understanding of the accuracy expectation of no blank forms. There were 13 notification opportunities with 7 marked "Actual" and 6 marked "Drill". The inconsistent form completion was discovered during EP's review of PI data from the LOR classes for the last three weeks of September in preparing the 3rd Quarter 2003 PI results. Reasonable assurance exists that the same error would not have occurred for an actual emergency since it is implicitly clear that "Actual" is to be marked during an actual event. The inconsistent form completion is addressed in the Corrective Action Program. FAQ 338 provide Palisades with the one time site specific allowance to count the forms as accurate with either drill or actual as long as one or the other was checked. The bases for this decision was that the lack of providing clear expectations to the LOR simulator crews on marking drill or actual event on the notification form is indicative of a programmatic weakness and not a performance weakness. Due to the short duration from the resolution of FAQ and 338 and the September NRC exam and the infrequency of the performance of simulator training EP drills, is it acceptable to apply	12/4 Introduced	Sequoyah

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		the similar resolution to SQN also on a one time basis? This would allow the notifications to be considered as accurate as long as either actual or drill was selected (completing all the appropriate blocks on the notification form).		
		Proposed Response: Yes, for this occurrence only. As first discussed in FAQ 338, the lack of providing clear expectations to the LOR simulator crews on marking drill or actual event on the notification form is indicative of a programmatic weakness not a performance weakness. Therefore including these events as failures would not provide an accurate indicator of actual performance with regard to the accuracy of the notification form		
36.4				