UNITED STATES
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August 16, 2001

MEMORANDUM TO: Mark Satorius, Chief
Performance Assessment Section
Inspection Program Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

FROM: August K. Spector, Communication Task Lead
Inspection Program Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

August K. Spector

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON AUGUST 15, 2001

On August 15, 2001 a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss and review the initial implementation of the revised reactor oversight process. An agenda, attendance list, and information exchanged at the meeting are attached. The following dates were established for future meetings: September 12, 2001.

Attachments:

1. List of Participants
2. Agenda
3.SCRAMS with loss of normal heat removal analysis of adding SCRAMS caused by total loss of feedwater
4. Industry trends Program Plans
5. Chart: Certificate of Compliance and Low Level Burial Ground
6. Frequently Asked Question Log # 15, 16, 20, 21, 22, 23, 24

cc: John W. Thompson, NRR/IIPB

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OFC:	DIPM/IIPB					
NAME:	ASpector					
DATE:	8/ 16 /01					

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NRC Public Meeting
Reactor Oversight Process
List of Participants
August 15, 2001

D. Hickman, NRC.
A. Madison, NRC
M. Johnson, NRC
M. Satorius, NRC
S. Ferrel, TVA
P. Loftus, COMED
L. Whitney, NRC
S. Floyd, NEI
T. Houghton, NEI
R. Ritzman, PSEG
M. Taylor, Exelon
A. Spector, NRR
W. Warren, SN
C. See, NRC
A. Halliday, Entergy
J. Thompson, NRC
R. Boyce, NRR
J. Weil. McGraw Hill
G. Cavahaugh, OPPD
T. Tickens, Nuclear Management Co.
D. Hembree, INPO

Attachment 1

AGENDA
ROUTINE ROP PUBLIC MEETING
8/15/2001

8:00AM	Welcome & Confirm Agenda	Alan Madison
8:10AM	WebPage Changes	Conchita See
8:20AM	Initiating Event PI Replacement RIS	Mike Johnson
8:45AM	Scrams w/LONHR PI Update	Leon Whitney
9:00AM	Unplanned Power Changes PI Replacement	Don Hickman
9:45AM	BREAK	
10:00AM	Revision to IMC 0305	Mike Johnson
10:30AM	Discussion of Draft IMC on Regulatory Oversight of Plants in Extended Shutdown	John Thompson
10:45AM	Industry Trends Update	Tom Boyce
11:00AM	Planning For Next Revision to NEI 99-02	Mike Johnson
12:00PM	Lunch	
1:00PM	Transportation SDP Discussion	Audrey Hayes
1:30PM	Discussion & Resolution of FAQs	Don Hickman
4:00PM	Adjourn	

Attachment 2

SCRAMS WITH LOSS OF NORMAL HEAT REMOVAL

ANALYSIS OF "ADDING" SCRAMS CAUSED BY TOTAL LOSS OF FEEDWATER

Prepared by: Leon Whitney
Prepared on: August 8, 2001

Issue: Whether, and to what degree, clarifying PI reporting criteria to commence consistent reporting of scrams with loss of normal heat removal caused by a total loss of feedwater will add to the number of plants crossing the threshold from green to white (the threshold being >2 such scrams over three years at the same reactor plant).

Question: What is the expected impact of such a clarification in reporting criteria? [Note that the PI Program goal is ~5% of plants having been in the non-green (white/yellow/red) bands during any 12 month period (i.e., the PI Program goal is a specific plant count of ~5 of the 103 plants over 12 months).

Population of plants: 103, so that the 5% PI Program goal would be exactly met by having ~5 different plants in the non-green bands during each of the two rolling four quarter/12 month sample periods (plant count of ~5). [As seen below, that current PI plant count runs at ~3.]

Data Reviewed: 2Q00, 3Q00, 4Q00, 1Q01, 2Q01 (five quarters of data, which provides for two 12 consecutive month rolling sample periods).

Assumption: Assume that plants that do not originally exceed a reporting value of 0 or 1 will normally not exceed the PI reporting value of 2 after the clarification is implemented. These plants are excluded from the analysis. [Below it is shown that only one additional scram per quarter, spread over all 103 reactor plants in the population, can be expected to occur as a result of clarification of the PI reporting guidelines, making this a reasonable assumption.]

Analysis:

- **Step 1:** Observe the reported values for the five quarters of available data for those plants reporting 2 or greater PI values:

2Q00:

Plant Name	Reported Value
Callaway	2
Calvert Cliffs 1	3 (non-green)
Diablo Canyon 1	2
Diablo Canyon 2	3 (non-green)
Indian Point 2	2
Millstone 2	2
Nine Mile 2	2
Oyster Creek	2
Point Beach 1	2
Prairie Island 1	2

Attachment 3

3Q00:

Plant Name	Reported Value
Callaway	2
Calvert Cliffs 1	**4** (non-green)
Diablo Canyon 1	2
Diablo Canyon 2	**3** (non-green)
Indian Point 2	2
Millstone 2	2
Nine Mile 2	2
Point Beach 1	2
Prairie Island 1	2

4Q00:

Plant Name	Reported Value
Callaway	2
Clinton	2
Calvert Cliffs 1	**3** (non-green)
Diablo Canyon 1	2
Diablo Canyon 2	2
Hatch 1	2
Millstone 2	2
Nine Mile Point 2	2
Point Beach 1	**3** (non-green)
Prairie Island 1	2

1Q01:

Plant Name	Reported Value
Callaway	2
Calvert Cliffs 1	**3** (non-green)
Clinton	2
Diablo Canyon 1	2
Diablo Canyon 2	2
Hatch 1	2
Millstone 2	2
Nine Mile Point 2	2
Point Beach 1	**3** (non-green)
Prairie Island 1	2
San Onofre 3	2

2Q01:

Plant Name	Reported Value
Callaway	2
Calvert Cliffs	**3** (non-green)
Clinton	2
Diablo Canyon 1	2
Diablo Canyon 2	2
Hatch 1	2
Millstone 2	2
Nine Mile Point 2	2

Point Beach 1	3 (non-green)
Point Beach 2	2
San Onofre 3	2

- **Step 2:** Observe that at any given time, ~8 plants typically tended to be on the verge of entering the non-green region (reported value 2) and ~2 plants typically tended to already be in the non-green region (with a reported value of 3, and in one case 4). Therefore, a typical population of plants on the verge of or in the non-green area is therefore 10.

- **Step 3:** Note that for the first sample period (2Q00, 3Q00, 4Q00, 1Q01) there were three plants counted in a non-green status (Calvert Cliffs 1, Diablo Canyon 2, and Point Beach 1). Also note that for the second sample period (3Q00, 4Q00, 1Q01, 2Q01) the same three plants were counted in a non-green status. So the typical actual PI plant count value (number of plants counted in a non-green status during each of the two sample four quarter/12 month periods) was **3 (~3% PI plant count compared to the 5% goal)**.

- **Step 4:** From 1987-1995 data, 86 out of 359 loss of normal heat removal events were initiated by a total loss of feedwater. Many of these events may not have been reported to the ROP in the past. Now, 86/359 = .24. So the worst case under-reporting is ~ 25%. Note (for use below) that missing 1/4 of the reportable events is equivalent to under-reporting by 1/3 of the reported value.

- **Step 5:** A review of the data for the five subject quarters shows that there were a total of 17 new scrams reported, for an average of 3.4 new scrams reported per quarter.

- **Step 6:** Since the under-reporting is ~1/3, then an additional average 1.1 (~1) scram per quarter would likely be reported if the reporting criteria were clarified to capture scrams with loss of normal heat removal caused by total loss of feedwater.

- **Step 7:** Since approximately 1 scram per quarter is distributed over all 103 plants, any population of 10 plants should receive approximately ~1/10 extra scrams per quarter.

- **Step 8:** By PI reporting criteria, each scram is counted for 3 years (12 quarters), so, under the revised reporting criteria, there would typically be an additional 1.2 scrams being counted in any population of 10 plants over 3 years/12 quarters.

- **Step 9:** Note that 1/5 of the time, the plant incurring an additional scram would be one of the (typical) 2 plants which already exceed the threshold, which would not change the number of plants exceeding the threshold. But 4/5 of the time, the plant incurring an additional scram would be one of the (typical) 8 plants that does not already exceed the threshold. In that case, the number of plants exceeding the threshold during the subject quarter would go from 2 to 3. Therefore, the effective number of extra scrams which cause a crossing of the threshold in a population of 10 plants over 3 years/12 quarters would be (4/5 X 1.2) = .96 (~1). This one effective additional scram would result in one additional reactor plant (typical total 3) being in a non-green status at any given time under clarified reporting criteria, and would also result in one additional reactor plant (typical total 4) being counted as exceeding the threshold during any four quarter, 12 month time period **(for an approximate 4% PI plant count under clarified reporting criteria, up from the ~3% shown above)**.

Conclusion: The impact of clarifying the reporting criteria to ensure the reporting of scrams with loss of normal heat removal which are caused by loss of feedwater should be the change of the typical four quarter/12 month scrams with loss of normal heat removal PI plant count from 3 to 4 **(a new value of ~4% PI plant count under clarified reporting criteria, up from ~3%, and as compared to the 5% PI Program goal).**

Industry Trends Program Plans

8/15/01

I. Milestones and Schedule:

9/01	- Publish charts on external web
Early 02	- RES initial update of initiating events in NUREG-5750
3/02	- Issue SECY on industry trends to support AARM
Fall 02	- RES initial update of system and component reliability studies
CY02	- Develop risk-informed thresholds for PIs using SPAR models
12/02	- Likely first full FY report on ROP PI data with agency action on any adverse trends

Major Tasks (Discussed in SECY-01-0111):

1. **Develop risk-informed thresholds** - RES will use SPAR Rev 3i models that are currently available to develop risk-informed thresholds for PIs where this is possible. SRM on SECY-01-0111 dated August 2, 2001 stated that threshold development should be done "as soon as practicable."

2. **Update Initiating Events and Reliability Studies** - RES update in CY02 and CY03.

3. **Improved Industry Data Collection and Reporting** - NRC staff will continue to work with INPO to develop consolidated data collection and reporting. Reporting could include ROP PIs, industry PIs, and INPO/WANO indicators.

Other Issues

4. **Improved Strategic Plan Performance Measures and Charts** - Potential improvements to the NRC's Performance Accountability Report to Congress to show trends in indicators vice current high-level criteria with bistable response (i.e., zero deaths from radiation)

5. **Publish industry trends data annually as a NUREG?** Is publication on the web good enough? Previously published as NUREG-1187 (series), "Performance Indicators for Operating Commercial Nuclear Power Plants." Some stakeholders have asked for a hard copy.

6. **Merging of AEOD and ROP data for scrams and SSFFs** - Initial look shows close agreement for scrams, some differences for SSFFs. May need NEI to assist with licensee interface in resolution of differences.

Attachment 4

Reactor Oversight Process Industry Trends

The NRC monitors trends in indicators of industry performance as a means to confirm that the safety of operating power plants is being maintained. The NRC reports to Congress each year regarding any statistically significant adverse trends in industry safety performance. The NRC formally reviews these indicators, as well as its response to adverse trends, as part of the Agency Action Review Meeting (AARM) process. The NRC's Industry Trends Program is described further in SECY-01-0111, "Development of an Industry Trends Program for Operating Power Reactors."

The status of the Industry Trends Program and results to date were discussed with senior NRC managers at the Agency Action Review Meeting in Atlanta, GA, on June 28, 2001, and with the Commission on July 19, 2001, as part of the AARM briefing. The following slides were used: Industry Trends (outline), Background, Purpose, Objectives, Approach, Process, Communications, Results to Date, and Future Development (see all briefing slides).

Industry Trend Charts by Cornerstones of Safety

Data Source	Initiating Events (IE)	Mitigating Systems (MS)	Barrier Integrity (BI)	Emergency Prepared-ness (EP)	Occupational Radiation Safety (OR)	Public Radiation Safety (PR)	Physical Protection (PP)
Ex-AEOD PIs	LT | ST	LT | ST			LT | ST		
ROP PIs	ST	ST	ST	ST	ST	ST	ST
ASP Program	LT	LT					

LT = long term (greater than 4 years by year) - - not yet available for ROP PIs
ST = short term (4 years by quarter)

The NRC currently uses 3 distinct sets of indicators to assess trends in industry performance, organized within the cornerstones of safety used by the ROP. The cornerstones are aligned with the NRC's strategic performance areas of reactor safety, radiation safety, and safeguards within the nuclear reactor safety arena.

(1) Ex-AEOD Performance Indicators - For many years, the NRC's former Office of AEOD published indicators in several NUREGs, including NUREG-1187 (series), "Performance Indicators for Operating Commercial Nuclear Power Reactors," using information derived from Licensee Event Reports (LERs) and plant Monthly Operating Reports (MORs).

The Ex-AEOD indicators include (with affected cornerstones in parenthesis):

- Automatic Reactor Scrams (IE)
- Safety System Actuations (MS)
- Significant Events (MS)

- Safety System Failures (MS)
- Forced Outage Rate (MS)
- Equipment Forced Outage Rate (MS)
- Radiation Exposure (OR)

(2) ROP Performance Indicators - Industry averages for the 18 plant-level performance indicators under the Reactor Oversight Process (ROP), using data submitted by individual plants.

The ROP indicators include (with affected cornerstones in parenthesis):

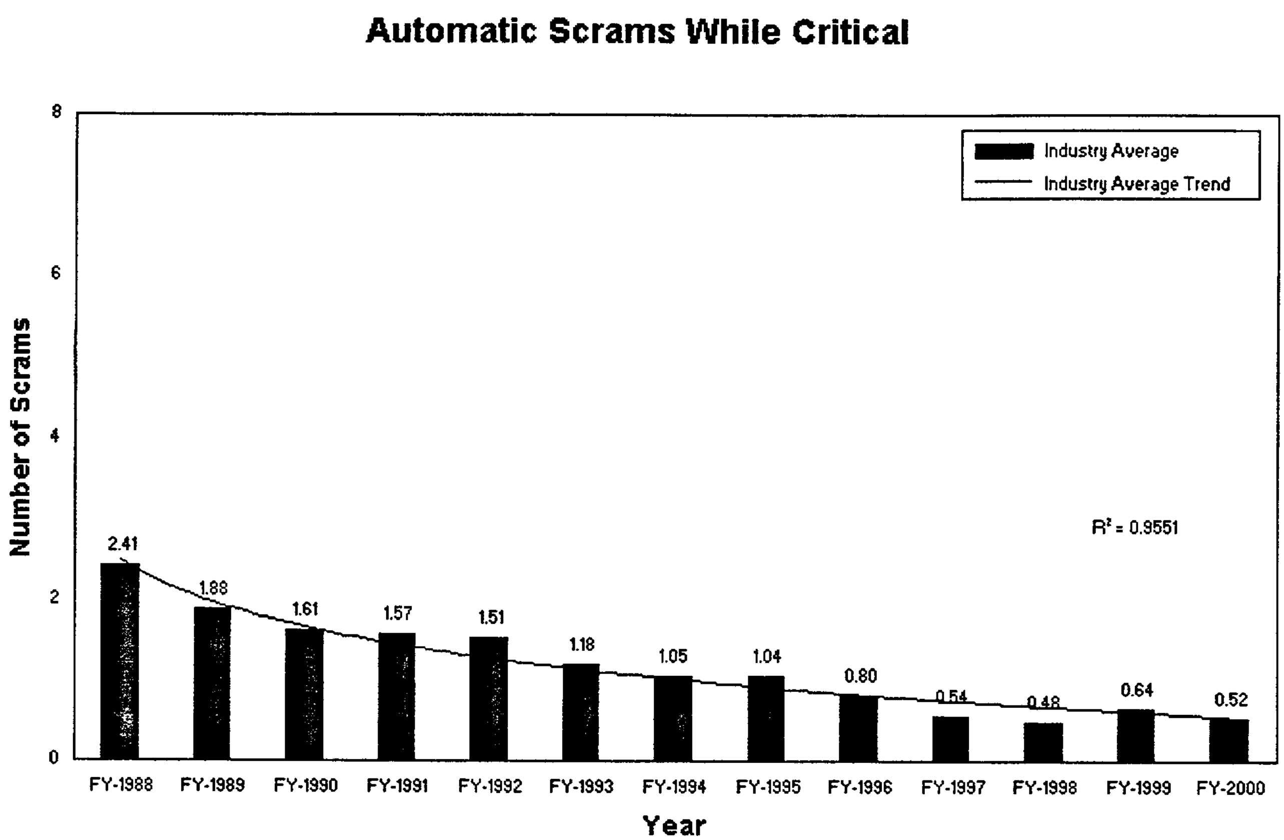
- Unplanned Scrams (BI)
- Scrams with Loss of Normal Heat Removal (BI)
- Unplanned Power Changes (BI)
- Unavailability, Emergency AC Power (MS)
- Unavailability, High Pressure Injection - HPCI (MS)
- Unavailability, High Pressure Injection - HPCS (MS)
- Unavailability, Heat Removal System - RCIC (MS)
- Unavailability, Heat Removal System - AFW (MS)
- Unavailability, Residual Heat Removal - PWR (MS)
- Unavailability, Residual Heat Removal - BWR (MS)
- Safety System Functional Failures - PWR (MS)
- Safety System Functional Failures - BWR (MS)
- Reactor Coolant System Activity (BI)
- Reactor Coolant System Leakage (BI)
- Drill/Exercise Performance (EP)
- ERO Drill Participation (EP)
- Alert & Notification System Reliability (EP)
- Occupational Exposure Control Effectiveness (OR)
- RETS/ODCM Radiological Effluent Occurrences (PR)
- Protected Area Security Equipment Performance (PP)
- Personnel Screening Program Performance (PP)

(3) Accident Sequence Precursor (ASP) Program - ASP events documented in the NUREG-4674 (series), "Precursors to Potential Severe Core Damage Accidents." The most recent status of the ASP program was reported to the Commission in SECY-01-0034, "Status Report on Accident Sequence Precursor Program and Related Initiatives," dated March 1, 2001.

The ASP indicators include (with affected cornerstones in parenthesis):

- Precursor Occurrence Rate (IE&MS)
- Conditional Core Damage Probability (IE&MS)

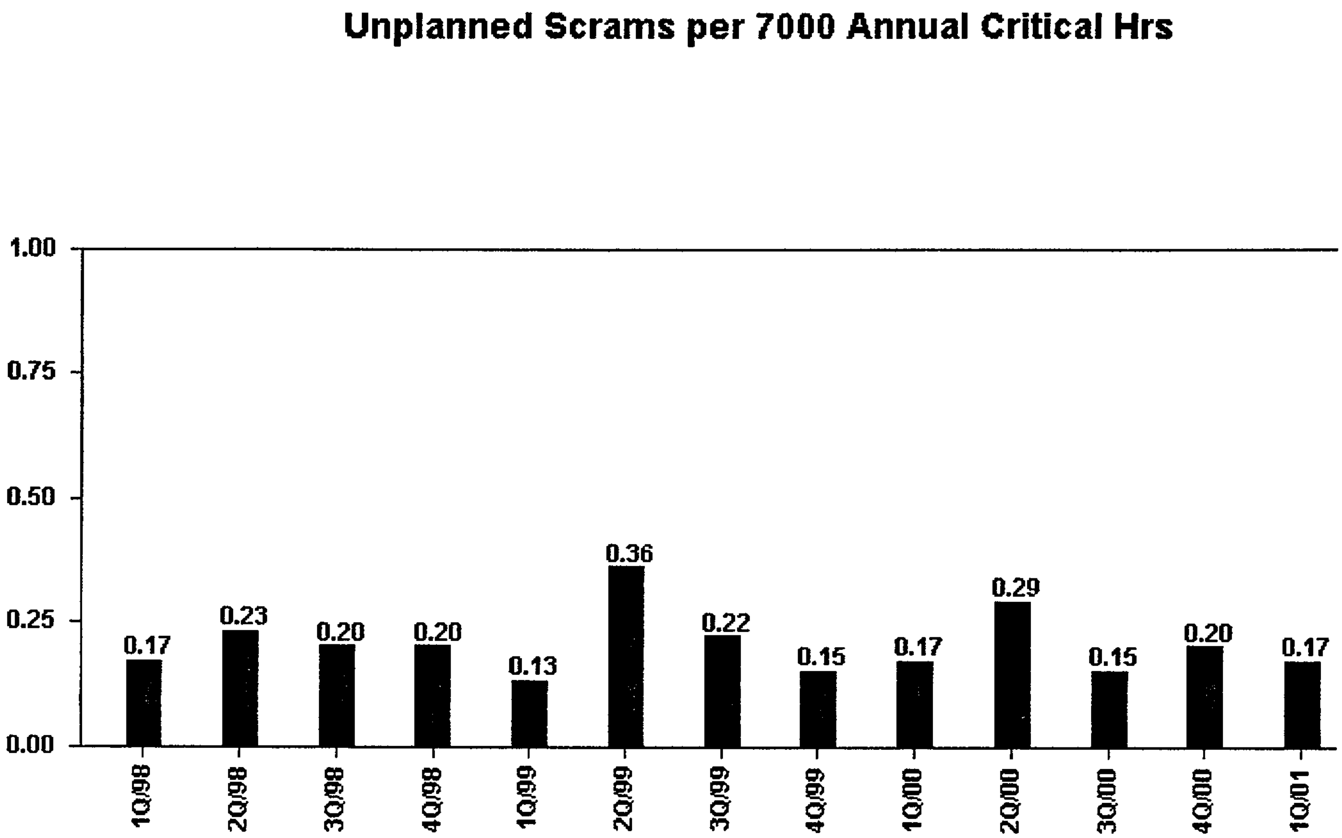
Updated July 30, 2001



EXAMPLE OF LONG TERM GRAPHS ON WEB

Initiating Events Cornerstone - Industry Trends

2Q/2001



Descriptions

EXAMPLE OF SHORT TERM GRAPHS ON WEB

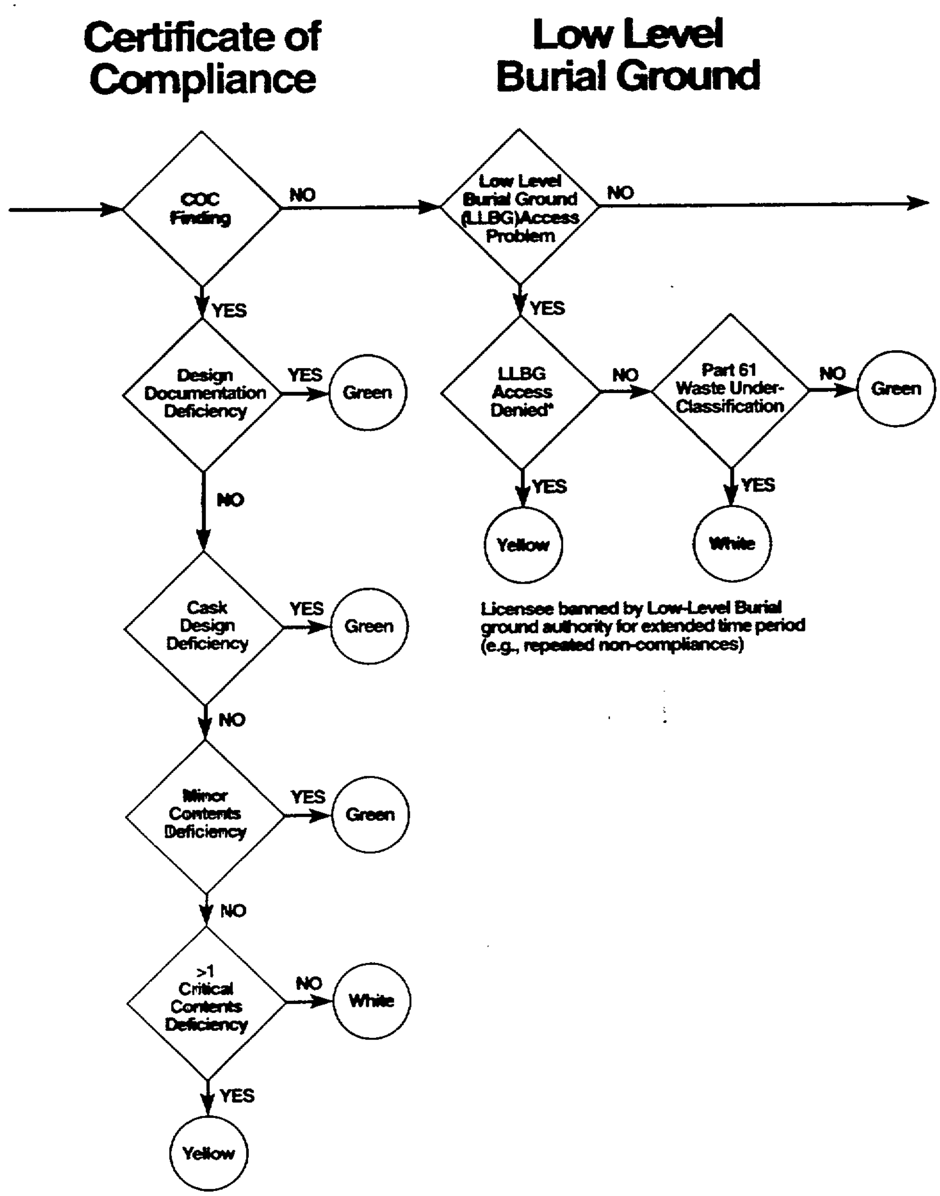
Cooper

				DEGRADED					
	4TH	1ST	2ND	3RD	4TH	1ST	2ND	3RD	4TH
	1W			1W 3W					
TOTAL	1W			5W	4W			0W	

				DEGRADED				MULTIPLE DEGRADED	
	1W			1W	3W			3W	0W
				2W	4W				
TOTAL	1W								

| NRC SUPPLEMENTAL INSPECTIONS →

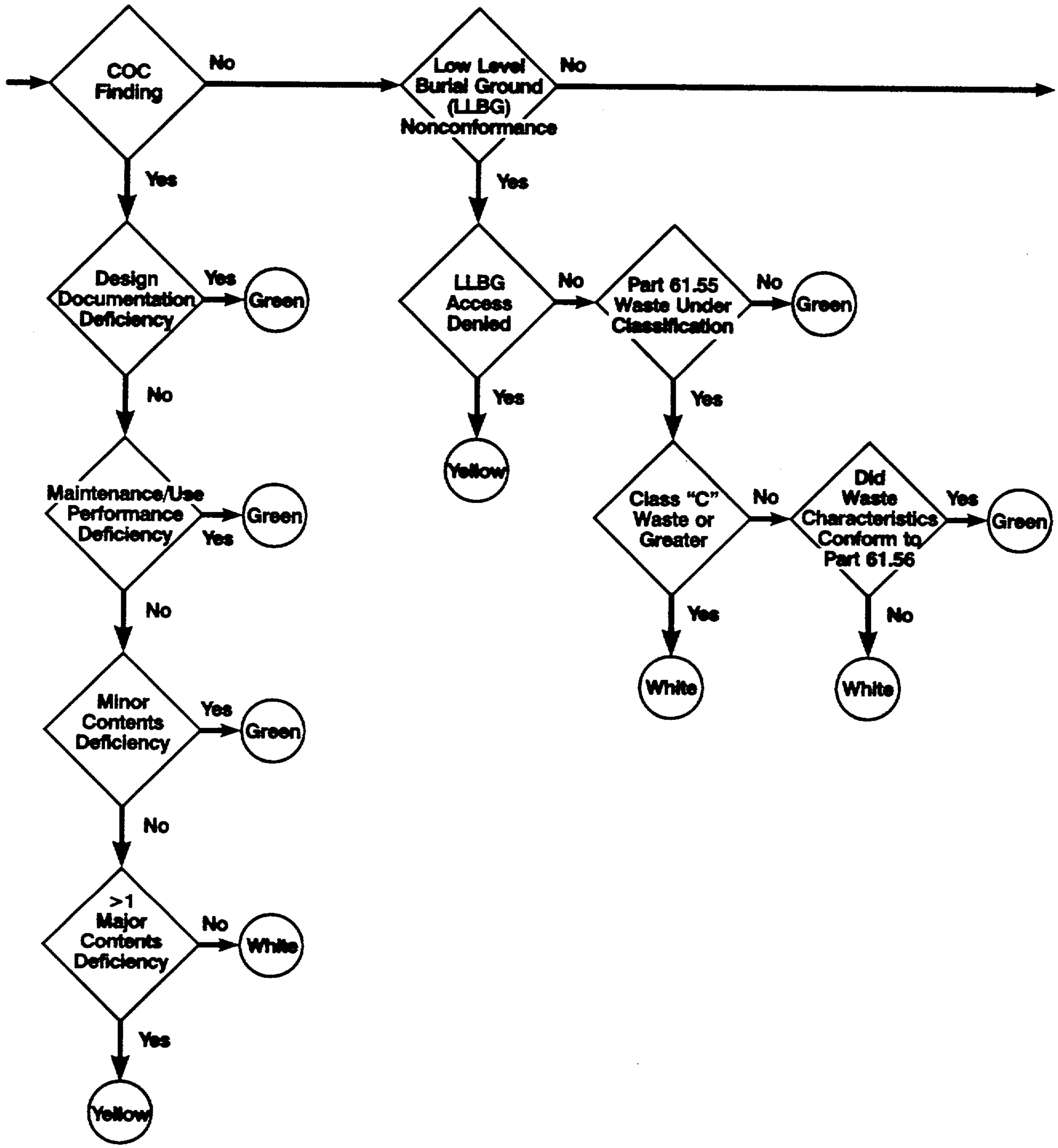
| LICENSEE RECOVERY PROGRAM, SELF-ASSESSMENTS, INDEPENDENT REVIEWS →



Attachment 5

Certificate of Compliance

Low Level Burial Ground



FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
15.12	MS01 MS02 MS03 MS04	**Question:** 1. Should support system unavailability be counted in the monitored safety system unavailability PI if analysis or engineering judgement has determined that the support system can be restored to available status such that the monitored system remains available to perform its intended safety function? 2. Do the criteria for determining availability described in NEI 99-02, Revision 0, page 26 lines 31-40 apply to this situation? **Licensee Proposed Response:** 1. No. During both testing and non-testing situations, the criteria described in NEI 99-02, Revision 0, page 33, lines 7-9 should apply, "In these cases, analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system." If the analysis or engineering judgment determines that the unavailability of the support system does not impair the ability of the monitored system to perform its intended safety function, then the support system unavailability should not be counted in the monitored system PI. For example, if engineering analysis determines that the unavailability of a ventilation support system for the emergency diesel generator does not adversely impact the availability of the emergency diesel generator to perform its intended function, the unavailability of the support system would not be counted in the emergency diesel generator PI. The engineering analysis must evaluate such things as; the length of time between an event and the time the ventilation system is required to be available to support the safety function of the emergency diesel generator, the complexity the actions required by plant operators to restore the availability of the ventilation system, and the probability of success for the restoration actions. Restoration actions should be contained in a written procedure and must not require diagnosis or repair. The engineering analysis must provide a high degree of assurance that the unavailability of the ventilation support system does not impact the ability of the emergency diesel generator to perform its safety function. This treatment is consistent with maintenance rule and PRA. 2. No. In NEI 99-02, Revision 0, page 26, lines 31-40, criteria for exclusion of planned unavailability for testing activities of monitored systems are described. The criteria established in this section describe required actions or barriers which must be in place during *testing* so that unavailability of the monitored system is not counted in the monitored system PI.	Introduced 10/31 12/5/00 – NEI, Licensee proposed response added. 3/2/01 – Discussed. FAQ to be discussed as part of SSU focus group.	ComEd

FAQ Log 16				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
16.11	MS02 MS04	**Question:** **Appendix D** At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. Marine mollusks, if allowed to grow larger than ¾" in size, can clog the condenser and component cooling water heat exchangers. This process is carried out over a six hour period in which the temperature is raised slowly in order to encourage fish to move toward the fish elevator so they can be removed from the intake. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR? **Response:** No. The period of heat treatment will not be considered as "unavailable" for the HPSI and RHR systems because of the utility's actions to limit the environmental impact of heat treatments. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions There are no unavailable hours.	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question 2/5/01 – need to know design basis **7/12 Tentative Approval**	San Onofre

FAQ Log 16				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
16.14	MS03	**Question:** **Appendix D Question** Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of 100% capacity turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report). The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0. The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators. The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power). The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator. The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" per NEI 99-02, Rev. 0, pages 30 - 31. Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated? (Note: this FAQ is similar to Appendix D questions for Palo Verde and Crystal River regarding the auxiliary feedwater system) **Response:** Based on the information provided, this pump should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes. See the Palo Verde Appendix D question.	Introduced 12/6 5/2 Discussed 5/31 Discussed **7/12 Tentative Approval**	Davis-Besse

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.1	MS01 MS02 MS03 MS04	**Question:** Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited. **Response:**	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.2	MS01 MS02 MS03 MS04	**Question:** When reporting safety system unavailable time there are periodic (such as weekly) evolutions that although they may not be simple actions to restore a safety system, they result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.6	IE03	**WITHDRAWN**	Introduced 2/8 Need more information 4/23 Question revised 5/2 Discussed 7/12 Discussed **Withdrawn**	

Temp No.	PI	Question/Response	Status	Plant/ Co.
20.3	MS04	**Appendix D Question:** FAQ for Mitigating System MS04 concerning CE Designed NSSS systems, "Alternative historical data correction method to convert 2 trains to 4 trains." Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde, San Onofre, St. Lucie, and Waterford 3 In FAQ # 172, approved on May 2, 2000 for use by CE plants (now in Appendix D), two methods for changing historical data from an initial 2 train report to a revised 4 train report were outlined. Specifically, the change report methodology was to perform one of the following changes to historical data: **1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.** **2. Recalculate and revise all historical data using this guidance.** For CE plants incorporating method 1, a non-performance related degradation in the PI calculation for Trains 3 and 4 (and the overall PI) was subsequently observed. This degradation occurred due to a decrease in the required hours in the denominator as the historical data was replaced by typically zero (0) or low required hours reported in the revised data (post Jan, 2000) in combination with artificially high unavailability hours in the numerator (due to the doubling of non-shutdown cooling related unavailability hours from the historical data). As a result, PI values would generally degrade over time regardless of performance until the historical data drops from the PI calculation. In some cases, plants projected a fall below the GREEN/WHITE threshold in 2002, even if perfect performance was used in the projection. **Licensee Proposed Response:** To address the calculation anomaly in the determination of the RHR PI, a third alternative is suggested for the estimation of Train 3 and Train 4 data: **3) Maintain Train 1 and Train 2 historical data as is. For Train 3 and Train 4, make a best effort to collect and report the number of unavailable hours and required hours for the historical data period. If data is not available an estimate may be provided.** If changes to historical data are made, then provide comments with the change report to identify the manner in which the historical data has been revised.	4/4 – Discussed. Need CE owners to provide additional input. 5/2 Discussed 5/31 Tentative Approval 7/12 NRC to discuss with residents **8/15 ON HOLD**	CE Plants
21.2	MS01 -04	**Question:** Removing (Resetting) Fault Exposure Hours **Licensee Proposed Response:** **TO BE ADDRESSED IN UNAVAILABILITY TASK FORCE**	**8/15 Withdrawn**	
21.4	MS01 -04	**Question:** By the NEI guidance, fault exposure hours can only be removed for "a single item" when the fault exposure hours associated with the item are greater than or equal to 336 hours. How are multiple failures of the same component handled when some of the failures have fault exposure hours less than 336 hours, yet the total of all the failures attributed to the same failed component are greater than 336 hours.?	5/2 Discussed . Response to be revised 5/31 Discussed	Southern Co.

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Proposed Response: Concerning groups of fault exposure hours that sum to greater than 336 hours, but are individually less than 336: Fault exposure hours may be removed on a case-by-case basis, provided the following criteria are met: • The applicable failures are associated with the same specific component and have the same root cause • Portions of the fault exposure hours are associated with management's conservative decision to increase the surveillance testing frequency in an attempt to verify effective corrective action and a failure occurred during the increased surveillance frequency • All other NEI 99-02 criteria for removing fault exposure hours have been met • The NRC supplemental inspection considered the failures associated with the condition • The removal received concurrence with the NRC via the FAQ process • A comment is placed in the comment field of the data submitted indicating more than one failure was considered in resetting the fault exposure hours		
21.6	IE02	**Question:** Some plants are designed to have a residual transfer of the non-safety electrical buses from the generator to an off-site power source when the turbine trip is caused by a generator protective feature. The residual transfer automatically trips large electrical loads to prevent damaging plant equipment during reenergization of the switchgear. These large loads include the reactor feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual transfer is completed the operators can manually restart the pumps from the control room. The turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be counted as a scram with a loss of normal heat removal? **Response** No. In this instance, the electrical transfer scheme performed as designed following a scram and the residual transfer. In addition the pumps can be started from the control room. Therefore, this would not count as a scram with a loss of normal heat removal	5/2 Introduced **7/12 Tentative Approval**	Nine Mile
21.8	MS01 ,02,03 ,04	**Question** **WITHDRAWN** **Response**		
21.9	MS01	**Question:** NEI 99-02 Revision 0, Page 1, INTRODUCTION, line 22 states: "Performance indicators are used to assess licensee performance in each cornerstone." Consider the situation where a certified vendor supplied a safety related sub-component for a standby diesel generator. This sub-component was refurbished, tested and certified by the Vendor with missing parts. The missing parts eventually manifested themselves as a sub-component failure that lead to a main component operability test failure. The Vendor issued a Part 21 Notification for the condition after notified by the Licensee of the test failure. (The licensee conducted a successful post maintenance surveillance and two subsequent successful monthly surveillances before the test failure. Thus there was fault exposure and unplanned maintenance unavailability incurred.) If a licensee is required to take a component out of service for evaluation and corrective actions related to a Part 21 Notification or if a Part 21 Notification is issued in response to a licensee identified condition (i.e. Report # 10CFR21-0081), should the licensee have to count the fault exposure and unplanned unavailability hours incurred? **Response:**	5/2 Introduced 5/31 Discussed 7/12 Discussed. Response explanation being prepared	FitzPatrick

Temp No.	PI	Question/Response	Status	Plant/ Co.
22.1	IE02	**Question** Should the following reactor trip described in the scenario below be reported as a "Scram with Loss of Normal Heat Removal?" A loud noise was heard in the Control Room from the Unit 2 Turbine Building. Operators noted a steam leak, but could not determine the source of the steam because of the volume of steam in the area. It was suspected that the leak was coming from the No. 21 or 22 Moisture Separator Reheater (MSR). The steam prevented operators from accessing the MSR manual isolation valves. Due to the difficulty in determining the exact source of the leak, the potential for personnel safety concerns, and the potential for equipment damage due to the volume of steam being emitted into the Turbine Building, operators manually tripped the Unit. After the manual trip, a large volume of steam was still being emitted, and the shift manager had the main steam isolation valves (MSIVs) shut. Once the MSIVs where shut, the operators identified a ruptured 2-inch diameter vent line from No. 21 MSR second stage to No. 25A Feedwater Heater. The operators shut the second stage steam supplies and isolated the leak. Once the leak was isolated, the MSIVs were opened and normal heat removal was restored. The majority of the steam that was emitted following the trip was due to all the fluid in the MSR and feedwater heater escaping from the pipe. **Response** Yes. **Investigation and diagnosis was required to determine that the main steam isolation valves could be reopened.**	5/31 Discussed 7/12 Discussed. Response explanation being prepared	Calvert Cliffs
22.2	IE02	**Question** Should the following reactor trip described in the scenario below be reported as a "Scram with Loss of Normal Heat Removal?" Following a reactor trip, No. 11 Moisture Separator/Reheater second-stage steam source isolation valve (1-MS-4025) did not close. The open valve increased the cooldown rate of the Reactor Coolant System. Control Room Operators closed the main steam isolation valves and used the atmospheric dump valves to control Reactor Coolant System temperature. Within three hours, 1-MS-4025 was shut manually. Control Room Operators opened the main steam isolation valves, and Reactor Coolant System temperature control using turbine bypass valves was resumed. **Response** Yes. **The normal heat removal path could not be restored from the control room without diagnosis or repair to restore the normal heat removal path. In this case, manual action was necessary outside the control room to manually isolate a valve to restore the normal heat removal path.**	5/31 Discussed 7/12 Discussed. Response explanation being prepared	Calvert Cliffs
23.1	MS01 -04	**Question** Can credit be taken for manual operator actions performed outside the control room to recover a failed support system function when the manual actions, while not a single action, are proceduralized and do not require diagnosis or repair?	7/12 To be addressed by Unavailability Task Force	Exelon
23.2	MS01 -04	**Question** When assessing the failure of a system or component to perform its safety function, can mission time be defined with reference to the station's probabilistic risk assessment (PRA)?	7/12 To be addressed by Unavailability Task Force	Exelon

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24.1	IE03	**Question** This spring the above water portion of the circulating water intake structure was removed. This action was required by two federal agencies due to the issue of the intake structure attracting, inadvertently trapping and leading to the demise of double crested cormorants (a protected migratory bird species). Anticipating the possibility of fouling, contingency work orders were created on April 3 before the intake demolition started for cleaning of the main condenser water boxes and condensate coolers. These activities anticipated the necessity for reductions in power by greater than 20% and prescribed plant operating criteria that would necessitate initiation of these cleaning activities in response to accumulation of marine debris. However, the exact dates when these power reductions and cleaning activities would occur could not be predicted greater than 72 hours in advance. Power was reduced by greater than 20% for cleaning attributable to the accumulation of marine debris due to the ongoing intake structure activities on May 19th and May 25th for Unit 2 and Unit 1, respectively. In both cases, the rapid deterioration in the monitored plant parameters dictated power reductions and cleaning in less than 72 hours from the onset of the conditions. In addition, a Tech Spec surveillance required main turbine stop and governor valve with turbine trip test, requiring a reduction in power to about 65%, had been scheduled approximately 12 months in advance to occur at a later date. Since Unit 2 required a load reduction to 50% due to marine fouling for water box cleaning, the Tech Spec surveillance was moved up to also take place during that power reduction. On June 27th, the conditions again rapidly deteriorated due to an influx of small forage fish. Power was reduced on Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the pump bay attributable to the accumulation of the fish. Unit 1 power level remained reduced at approximately 80% while personnel performed Unit 2 traveling screen repair, condensate cooler cleaning on Unit 1 and removal of fish to regain water level. Would any of these power changes in excess of 20% be counted for this indicator? **Licensee Response** No. As discussed on p. 17 of NEI 99-02 Revision 1, if the power reductions were anticipated in response to expected problems (such as accumulation of marine debris and biological contaminants in certain season), a part of a contingency plan and not reactive to the sudden discovery of off normal conditions, they would not count. The planned maintenance power reduction to 65% would still be considered planned since it was planned greater than 72 hours in advance of its occurrence.	8/15 Introduced	WEPCO
276	MS04	Appendix D: Susquehanna Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because, as stated in the FSAR, the system's response to design basis LOCA/LOOP events while in SPC configuration determined that a usage factor of 10% is acceptable. The probability of the event of concern is 6.4 E-10.If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing? No, because the plant is being operated in accordance with technical specifications, **as stated in the FSAR.**	8/15 – Revised, previously approved	

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24.2	BI01	**Question:** Our Chemistry Dept was questioned as to whether or not RCS strip isotopic data was included in the PI reporting for RCS Specific Activity. [We had not been reporting results from that method since it wasn't exactly like the method we typically used to satisfy our Tech Specs.] BVPS uses the RCS Isotopic Iodine Analysis method which is specific for isotopic Iodine in RCS (and is more accurate) for meeting our Tech Spec requirement. (We use all results even if the number of samples exceeds the TS requirement.) We also perform an RCS Strip Isotopic Analysis which is for gaseous and all other liquid isotopes in the RCS. This Strip method however, will provide isotopic Iodine in the results (although less accurate.) This method sometimes provides a higher value than the highest Iodine Isotopic analysis I-131 data for the month. However, this method is also considered to be an acceptable method for meeting the Tech Spec requirement, and is used if problems are encountered with the Isotopic Iodine method. Should ONLY the RCS Isotopic Iodine Analysis method (most accurate) for RCS samples be used for the results and determination of maximum RCS Specific Activity to be reported? ..or Should ALL isotopic samples of RCS, including those using less accurate analytical methods (e.g. Stripped liquid method) be considered for determination of maximum RCS Specific Activity? **Response:** No. Use the results of the method that was used to satisfy the technical specifications.	8/15 Introduced	Beaver Valley
24.3	MS-01 to 04	**Appendix D Question** Safety System Unavailability (SSU) indicators for Cook Units 1 and 2 are not calculated due to insufficient reported data. The SSU indicators and performance thresholds require 12 quarters of operational data to calculate unavailability and determine safety system performance. Cook Unit 1 returned to service December 18, 2000, after a 39-month forced outage and Unit 2 on June 25, 2000, after a 33-month forced outage. SSU indicator data has been reported for both units since the second quarter of the year 2000. Historical data was not reported since unavailability was not monitored during the extended outages. Cook Nuclear Plant (CNP) wants the SSU indicators to reflect actual safety system performance and have the indicators calculated with submitted data vice waiting until April 2003 for 12 quarters of data to be collected. What actions can be taken to have calculated SSU indicators and appropriately account for the effects of a T/2 fault exposure? **Licensee Response:** 1. Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational data, then the time would be reported but not calculated for the SSU indicator. The inspection and SDP process would then evaluate the T/2 fault exposure. 2. Submit a change report replicating submitted data to complete 12 quarters of data. This would give 12 quarters of operational data for safety system performance evaluation. . 3. Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational data, then re-construct the "zero-summed" unavailability data, where available, to provide 12 quarters of data. The T/2 fault exposure would then be evaluated as provided for in the Action Matrix.	8/15 Introduced	Cook Nuclear Plant