UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 21, 2000

MEMORANDUM TO: Alan Madison, Acting 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

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON September 20 - 21, 2000

On September 20-21, 2000 a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss the Reactor Oversight Process initial implementation. An agenda of the meeting, the attendance list, and information exchanged at the meeting are attached.

Attachments:

1. Meeting Agenda
2. Attendance List
3. Proposal for removing fault exposure hours from the Safety System Unavailability PI
4. Reactor Power Reductions per 7,000 Critical Hours PI
5. Unplanned reactor shutdowns with loss of normal heat removal (NRC version)
6. Unplanned reactor shutdowns with loss of normal heat removal (NEI version)
7. Proposed operator requalification human performance SDP (Sept. 2000 NRC draft)
8. Proposal for RCIC reporting
9. NRC Inspection Manual Chapter 0608 Performance Indicator Program (draft)
10. Frequently Asked Questions, Log. 8, 9, 10, 11, 12, 13, 14

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Contact: August K. Spector
301-415-2140

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OFC:	DIPM/IIPB		DIPM/IIPB			
NAME:	ASpector		A. Madison			
DATE:	09/21 /00		09/ /00			

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AGENDA

PUBLIC MEETING TO DISCUSS IMPLEMENTATION OF THE REVISED REACTOR OVERSIGHT PROCESS

DATE AND TIME: September 20 and 21, 2000
8:00 a.m. - 3:30 p.m.

TOPICS:

1. Consideration of issues associated with fault exposure time impact on Unavailability Performance Indicators and potential approaches to resolution -- see attachment
2. Process for approval and posting on the web Frequently Asked Questions
3. Status report on initiating Event pilot study
4. Discussion of draft Manual Chapter 0608, Performance Indicator Program -- see attachment
5. Discussion of reactor operator Significance Determination Process: see attachment
6. Status report on Cross-cutting Issues Working Group
7. Review and approval of Frequently Ask Questions -- see attachment
8. Determination of next meeting dates (October 31, 2000 and December 6, 2000)
9. Initial Implementation Evaluation Panel up-date
   Panel to meet 11/1-2/00
10. Future Federal Register Notice update
11. Regional Public Workshops update
    October 3 - Region 3
    Nov. 15, Region 4
    Nov. 16, Region 2
    December 13, Region 1
12. Future revision of NEI 99-02

NEXT MEETINGS:

October 31, 200
December 6, 2000

Attachment 1

NRC Public Meeting
Reactor Oversight Process
Attendance List
September 20-21, 2000

K. Borton, PECO Energy
P. Loftus, COMED
W. Dean, NRC
D. Hickman, NRC.
R. L. Sullivan, NRC
A. Madison, NRC
A. Spector, NRC
M. Ferdig
S. Floyd, NEI
T. Houghton, NEI
J. Butler, NEI
D. Olson, Dominion Gen
J. Jacobson, NRC
J. Mundy, NRC
W. Warren, Southern Nuclear
J. Nagle, PSEG
A.K. Krainik, APS
D. R. Robinson, NPPD
R. Eckenrode, NRR
D. Trimble, NRR
S. Sanders, NRC
S. Ketelsen, Pacific Gas
J. Hutton, PECO Energy
J. Butler, NEI
M. Taylor, PECO

Attachment 2

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PROPOSAL FOR REMOVING FAULT EXPOSURE HOURS FROM THE SAFETY SYSTEM UNAVAILABILITY PI

For any of the monitored safety systems, a single surveillance test failure that results in fault exposure hours that alone are sufficient to cause the indicator to cross the green-white threshold may be excluded from the calculation. Those fault exposure hours should be reported in the Comments field of the quarterly report to the NRC.

Fault exposure hours of shorter duration or caused by other events or conditions will be reported and included in the calculation. However, the NRC may consider increments of fault exposure hours for removal on a case-by-case basis. Factors to be taken into consideration would include the cause of the fault exposure, the number of hours, the impact on the indicator of those hours, the licensee's response to the event or condition, and the length of time the indicator would be non-green with those hours included in the calculation.

Attachment 3

Revised Treatment of Fault Exposure Hours

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Safety System Unavailability is currently computed under the Reactor Oversight Process (ROP) by adding, for each train, planned unavailability, unplanned unavailability and fault exposure hours and dividing the sum by the train hours, and then averaging the train values.

Fault exposure hours are intended to be a surrogate for unreliability. NEI 99-02 includes a provision for removing fault exposure hours after 4 quarters to "reset" the indicator. This is to remedy the condition where a single fault exposure of sufficient duration can cause the indicator to trip the G/W threshold and keep the indicator "non-green" for extended periods of time. Keeping the indicator "non-green" potentially masks future problems and falsely projects an image of system performance that is not indicative of the current system performance.

It was expected that the exercise of the fault exposure removal feature would be relatively rare compared to entry into the non-green zones due to planned and unplanned unavailability. Experience in the pilots and industrywide program to date suggest otherwise. All but one of the 11 non-green indications for safety system unavailability is as a result of large, single fault exposure terms. For the NRC, the action matrix dictates a supplemental inspection, yet the inspections have been very minimal because the cause of the tripped indicator was well known. This leaves the NRC open to criticism.

The following proposal would remedy the above concerns:

1. Licensees continue to report all fault exposure hours.

2. Fault exposure hours are excluded from the calculation of system unavailability.

3. Licensees would annotate the comment field to identify any single conditions that contributed more than 336 hours to the reported fault exposure hours.

4. The baseline inspection program would be modified to direct the inspectors to apply the SDP and determine if there were any performance issues associated with the system/train failure. The results of the SDP would be used to characterize any findings. This appears to be current NRC inspection practice and would, therefore, not result in an appreciable change in inspection hours for the ROP.

5. A historical review of performance data would be performed to determine if extracting fault exposure hours from the calculation would change the threshold values. Sufficient historical data is available for this review.

It is proposed that the above change be incorporated in the program as soon as possible.

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Reactor Power Reductions per 7,000 Critical Hours

Purpose
This indicator monitors the number of reactor power reductions of greater than 20 percent of full power. It may provide leading indication of risk-significant events but is itself not risk-significant.

Indicator Definition
The number of reductions in average daily power level of more than 20 percent from the previous day during the previous four quarters per 7,000 critical hours.

Data Reporting Elements
The following data are reported for each reactor unit:

- the number of reductions in average daily power level of more than 20 percent from the previous day in the previous quarter
- the number of hours of critical operation in the previous quarter

Calculation
The indicator is determined using the values for the previous four quarters as follows:

$$\text{value} = \frac{\text{(number of reactor power reductions in the previous 4 qtrs)}}{\text{(number of critical hours in the previous 4 qtrs)}} \times 7{,}000 \text{ hrs}$$

Definition of Terms
Average Daily Power Level: the net electrical energy during the day (measured from0001 to 2400 hours inclusive) in megawatts electric.

Net Electrical Energy Generated: gross electrical output of the unit measured at the output terminals of the turbine generator during the reporting period, minus the normal station service electrical energy utilization. If this quantity is less than zero, a negative number should be recorded.

Unit: the set of equipment uniquely associated with the reactor, including turbine generators and ancillary equipment, considered as a single electrical energy production facility.

Power Reduction: a reduction in the average daily power level of more than 20 percent from the previous day.

Critical hours: the total clock hours in the report period during which the reactor sustained a controlled chain reaction.

Attachment 4

UNPLANNED REACTOR SHUTDOWNS WITH LOSS OF NORMAL HEAT REMOVAL

Purpose

This indicator monitors that subset of unplanned reactor shutdowns in which the normal heat removal path is lost shortly before or shortly after an unplanned reactor shutdown. These shutdowns are more risk-significant than uncomplicated unplanned reactor shutdowns.

Indicator Definition

The number of unplanned reactor shutdowns while critical at or above the point of adding heat during the previous 12 quarters that were caused by or involved an unplanned 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.

Data Reporting Elements

The following data are reported for each reactor unit:

- the number of unplanned reactor shutdowns while critical at or above the point of adding heat in the previous quarter that were caused by or involved an unplanned 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.

Calculation

The indicator is determined using the values reported for the previous 12 quarters as follows:

value = total number of unplanned reactor shutdowns while critical at or above the point of adding heat during the previous 12 quarters that were caused by or involved an unplanned 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

Definition of Terms

Loss of the normal heat removal path: decay heat cannot be removed through the main condenser when any of the following conditions occur (see clarifying notes below):

- complete loss of all main feedwater flow
- complete loss of condenser vacuum
- complete closure of at least one MSIV in each main steam line
- failure of one or more turbine bypass valves to maintain reactor pressure and temperature at the desired operating condition

Attachment 5

Complete loss of condenser vacuum: a loss of condenser vacuum that prevents the condenser from removing decay heat after an unplanned reactor shutdown.

Unplanned reactor shutdown means the shutdown of the reactor in response to off-normal conditions or events by the unplanned addition of negative reactivity by any means, e.g., insertion of control rods, boron, or opening reactor trip breakers. Unplanned reactor shutdowns are those that bring the reactor from criticality to a shutdown mode within 15 minutes of commencing to insert negative reactivity.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical.

Clarifying Notes

Unplanned reactor shutdowns with loss of normal heat removal can occur in two ways: (1) the loss of the normal heat removal path causes the unplanned shutdown; or (2) the loss of the normal heat removal path occurs after the unplanned shutdown. In either case, the normal heat removal path is considered to be unavailable. 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.

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 (as long as the feedwater valves or MSIVs are capable of being reopened by operator demand) are not included. However, operator actions to mitigate the initiating event (e.g., closing MSIVs to isolate a steam leak) are included.

Examples of a complete loss of all main feedwater flow: trip of the only operating feedwater pump while operating at reduced power; loss of a startup or an auxiliary feedwater pump normally used during plant startup; loss of all operating feed pumps due to trips caused by low suction pressure, loss of seal water, or high water level (BWR reactor level or PWR steam generator level); unplanned reactor shutdown due to loss of all operating feed pumps; unplanned reactor shutdown in response to feed problems characteristic of a total loss of feedwater flow; and inadvertent isolation or closure of all feedwater control valves prior to an unplanned reactor shutdown.

Examples of loss of condenser vacuum: trip of all circulating water pumps; traveling screen blockage; condenser leakage; trip of all condensate pumps on high condensate temperature due to loss of condenser vacuum.

Examples of complete closure of at least one MSIV in each main steam line: automatic closure of all MSIVs as part of an engineered safety feature actuation; spurious closure of all MSIVs.

Example of loss of turbine bypass capability: sustained use of one or more atmospheric dump valves (PWR) or safety relief valves to the suppression pool (BWR) after an unplanned reactor shutdown.

Examples that do not count: loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power; loss of condenser vacuum resulting from an unplanned reactor shutdown in response to a plant event that had no direct effect on the main condenser vacuum; partial losses of condenser vacuum or turbine bypass capability after an unplanned reactor shutdown in which sufficient capability remains to remove decay heat; momentary operations of PORVs or safety relief valves.

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File

UNPLANNED REACTOR SHUTDOWNS WITH LOSS OF NORMAL HEAT REMOVAL

Purpose

This indicator monitors that subset of unplanned reactor shutdowns where unplanned loss of normal heat removal either caused the unplanned shutdown, or complicated the recovery. These shutdowns are therefore more risk-significant than uncomplicated unplanned reactor shutdowns.

Indicator Definition

The number of unplanned reactor shutdowns (while critical at or above the point of adding heat) during the previous 12 quarters that were caused by or involved an unplanned 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.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of unplanned reactor shutdowns (while critical at or above the point of adding heat) in the previous quarter that were caused by or involved an unplanned 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

Calculation

The indicator is determined using the values reported for the previous 12 quarters as follows:

value = total number of unplanned reactor shutdowns (while critical at or above the point of adding heat) during the previous 12 quarters that were caused by or involved an unplanned 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

Definition of Terms

Unplanned loss of the normal heat removal path: decay heat cannot be removed through the normal path when any of the following conditions occur (see clarifying notes below):

- total loss of feedwater flow
- loss of condenser vacuum
- inadvertent closure of all MSIVs
- turbine bypass unavailable

Attachment 6

total loss of feedwater flow: a complete loss of all main feedwater flow

loss of condenser vacuum: a decrease in condenser vacuum that leads to an unplanned reactor shutdown, or turbine trip; or a complete loss of condenser vacuum that prevents the condenser from removing decay heat after an unplanned reactor shutdown.

inadvertent closure of all MSIVs: a complete closure of at least one MSIV in each main steam line

turbine bypass unavailable: failure of one or more turbine bypass valves to maintain the reactor pressure and temperature at the desired operating condition

Unplanned reactor shutdown means the shutdown of the reactor in response to off-normal conditions or events by the unplanned addition of negative reactivity by any means, e.g., insertion of control rods, boron, or opening reactor trip breakers. Unplanned reactor shutdowns are those that bring the reactor from criticality to a shutdown mode within 15 minutes of commencing to insert negative reactivity.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical.

Clarifying Notes

Unplanned reactor shutdowns with loss of normal heat removal can occur in two ways: (1) the loss of normal heat removal causes the unplanned shutdown; or (2) the loss of normal heat removal occurs after the unplanned shutdown and complicates the plant shutdown process. In the second case, the determining factor is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path. For example, operator actions to secure the normal heat removal path to control the reactor cooldown rate or water level do not count as long as the normal heat removal path is still available to the operator. However, actions taken to mitigate the initiating event (e.g., closing MSIVs to isolate a steam leak) do count.

Unplanned reactor shutdowns with loss of normal heat removal at low power within the capability of the PORVs are not counted if the main condenser has not yet been placed in service, or has been removed from service.

Examples of total loss of feedwater flow:

Trip of the only operating feedwater pump while operating at reduced power; the loss of a startup or an auxiliary feedwater pump normally used during plant startup; the loss of all operating feed pumps due to trips caused by low suction pressure, loss of seal

water, or high water level (BWR reactor level or PWR steam generator level); unplanned reactor shutdown due to loss of all operating feed pumps; and unplanned reactor shutdowns in response to feed problems characteristic of a total loss of feedwater flow.

This category also includes the inadvertent isolation or closure of all feedwater control valves prior to an unplanned reactor shutdown; however, a main feedwater isolation caused by valid automatic system response after an unplanned reactor shutdown is not counted.

Design features to limit the reactor cooldown rate or to control water level subsequent to an unplanned reactor shutdown (e.g., closure of the main feedwater valves on a unplanned reactor shutdown) are not counted in this indicator.

Loss of feedwater flow caused by loss of offsite power does not count

Examples of loss of condenser vacuum:

Faults that contribute to a loss of condenser vacuum include: circulating water pump trips, traveling screen blockage, and condenser leakage

Loss of condenser vacuum caused by loss of offsite power does not count

Loss of condenser vacuum resulting from an unplanned reactor shutdown in response to a plant event that had no direct effect on the main condenser vacuum do not count

Partial losses of condenser vacuum that exist after an unplanned reactor shutdown in which sufficient capability remains to remove decay heat are not counted in this indicator.

Examples of inadvertent closure of all MSIVs:

Automatic closure of all MSIVs as part of an engineered safety feature actuation

This category does not include a manual closure of all MSIVs to limit cooldown rate after an unplanned reactor shutdown, as long as the MSIVs are capable of being reopened by operator demand. However, actions taken to mitigate the initiating event (e.g., closing MSIVs to isolate a steam leak), do count.

Examples of loss of turbine bypass unavailable:

Turbine bypass failures may result in an unplanned reactor shutdown during an unsuccessful turbine run back. However, partial losses of turbine bypass capability that exist after an unplanned reactor shutdown in which sufficient capability remains to remove decay heat are not counted in this indicator.

Sustained use of one or more atmospheric dump valves (PWR) or safety relief valves to the suppression pool (BWR) after an unplanned reactor shutdown would count in this indicator. However, momentary operations of PORVs or safety relief valves are not counted.

This category does not include turbine bypass valve closures caused by loss of off-site power.

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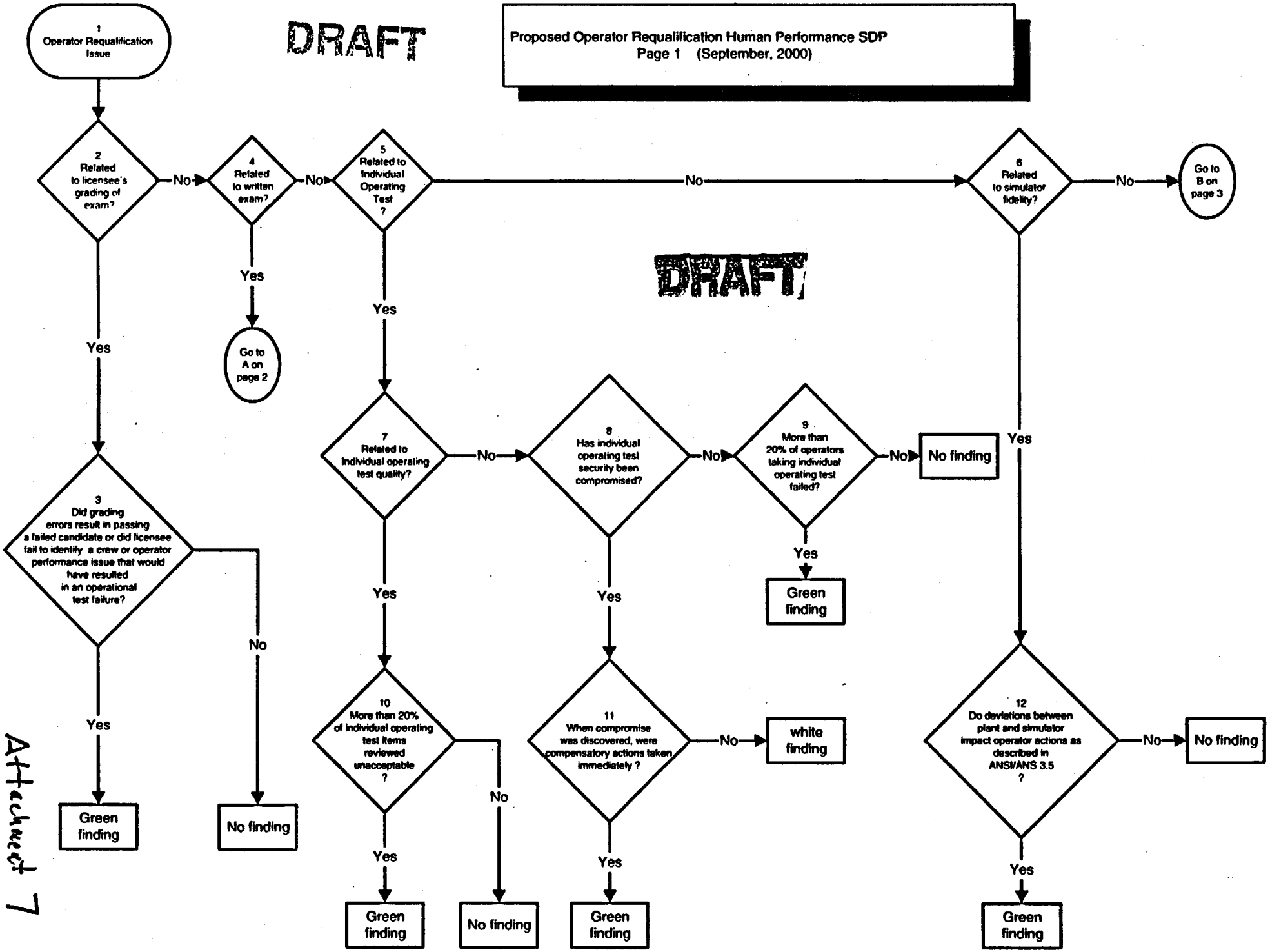
Proposed Operator Requalification Human Performance SDP
Page 1 (September, 2000)



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Attachment 7

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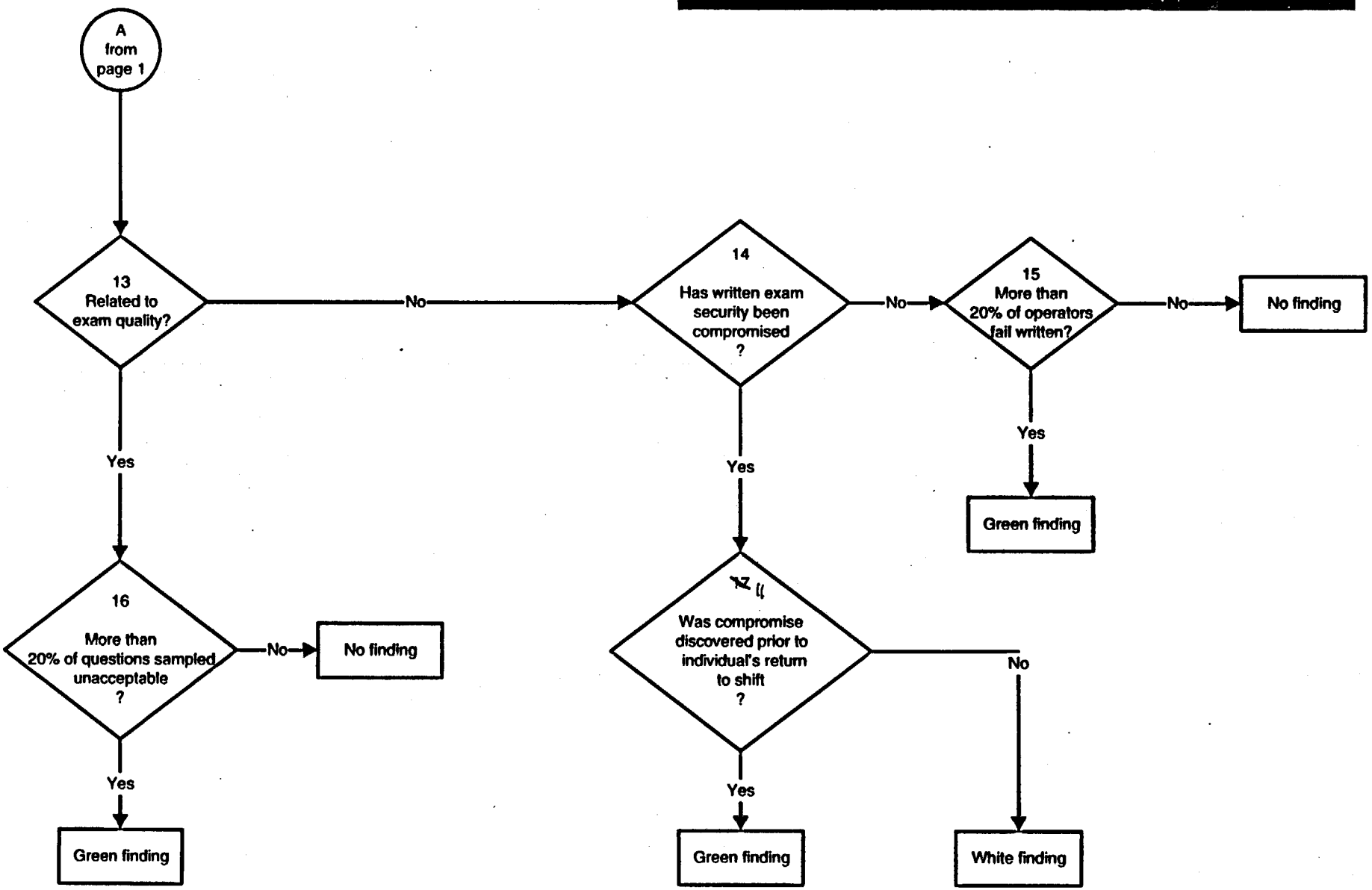
Proposed Operator Requalification Human Performance SDP
Page 2 (September, 2000)



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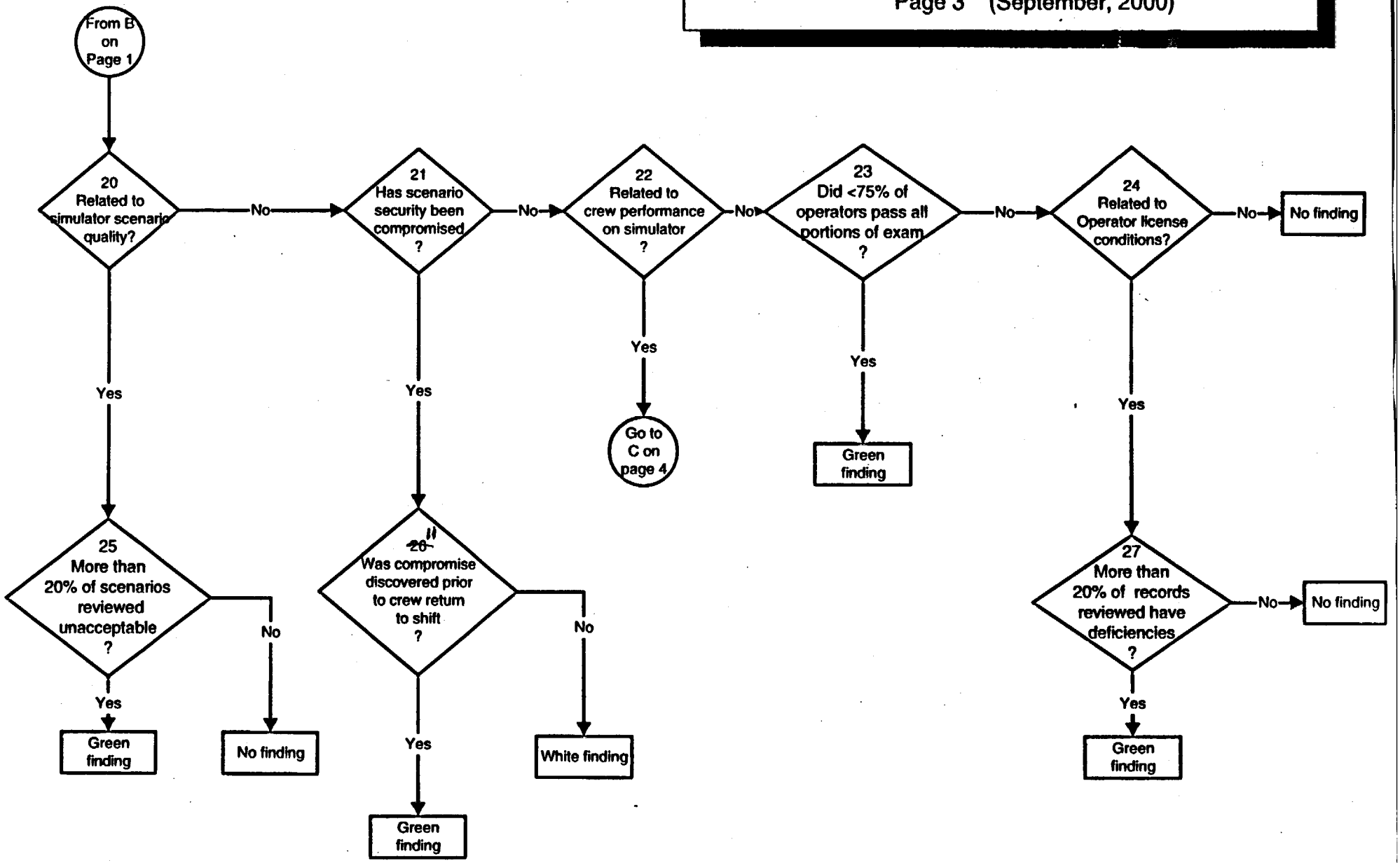
Proposed Operator Requalification Human Performance SDP
Page 3 (September, 2000)



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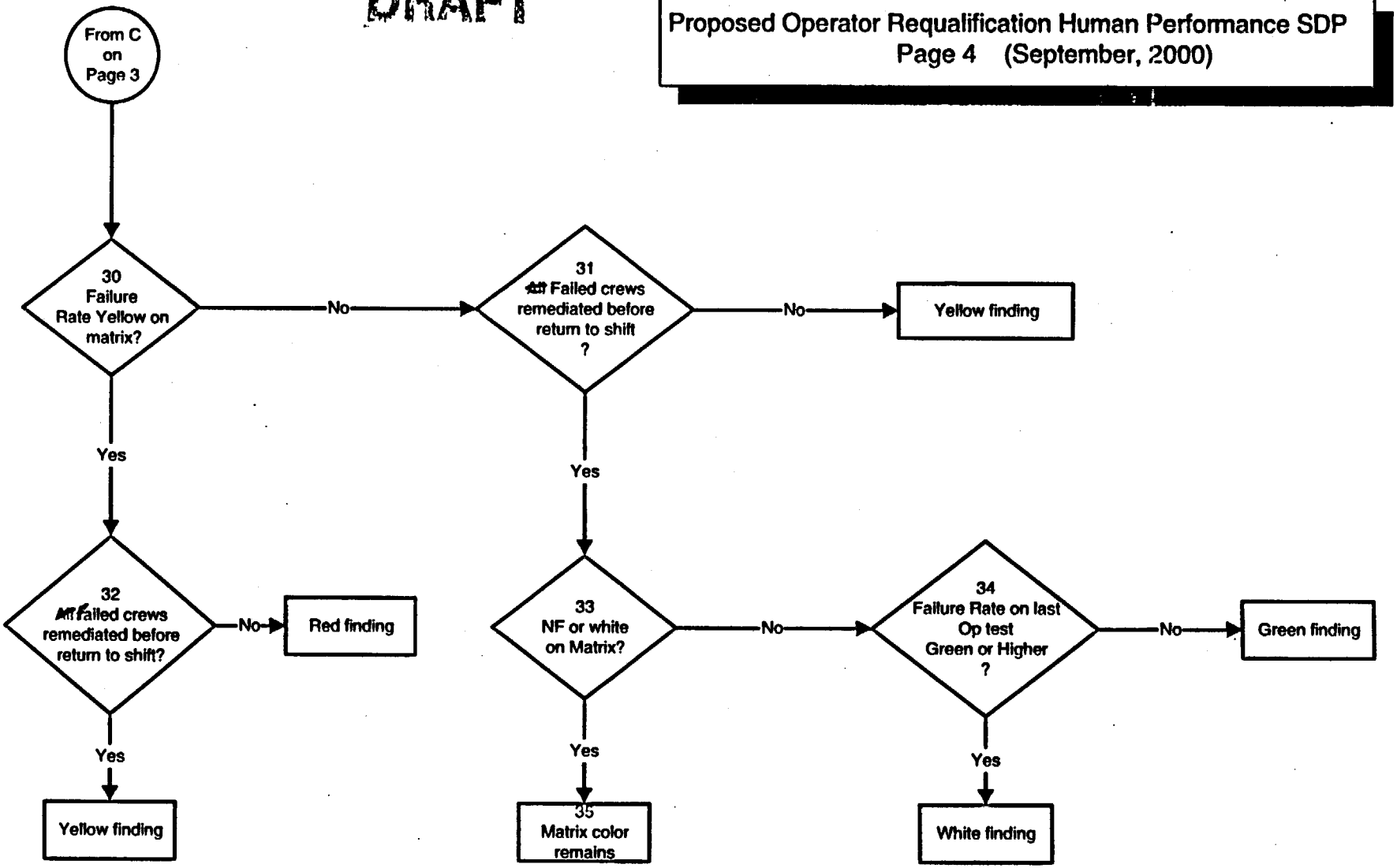
Proposed Operator Requalification Human Performance SDP
Page 4 (September, 2000)



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Simulator Operational Evaluation

August 29, 2000

Number of Crews with UNSAT Performance in the Annual Operating Test

Number of Crews that took the Annual Operating Test (Includes Dual Units)	1	2	3	4	5	6	7	8
4	G	W	Y	Y	NA	NA	NA	NA
5	G	W	Y	Y	Y	NA	NA	NA
6	NF	G	W	Y	Y	Y	NA	NA
7	NF	G	W	Y	Y	Y	Y	NA
8	NF	G	W	W	Y	Y	Y	Y
9	NF	G	G	W	Y	Y	Y	Y
10	NF	G	G	W	W	Y	Y	Y
11	NF	NF	G	W	W	Y	Y	Y
12	NF	NF	G	G	W	W	Y	Y
13	NF	NF	G	G	W	W	W	Y
14	NF	NF	G	G	W	W	W	Y

NF = < 20% Failure Rate - No Finding
G = 20 - 34% Failure Rate
W = >34 - 50% Failure Rate (NUREG-1021, Rev 8 - UNSAT Requal Program)
Y = >50% Failure Rate
NA = Not Applicable

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PROPOSAL FOR RCIC REPORTING

Add a new paragraph on page 78 of NEI 99-02 after *The Definition of SSFFs* and before *NUREG-1022* to read as follows:

Reactor Core Isolation Cooling Reportability: The Reactor Core Isolation Cooling (RCIC) System has operability requirements in the technical specifications because is needed to remove decay heat and is a risk-significant system. Therefore, events or conditions that prevented, or could have prevented, RCIC from fulfilling its function are included in this indicator.

Attachment 8

File Copy

NRC INSPECTION MANUAL

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Manual Chapter 0608

PERFORMANCE INDICATOR PROGRAM

0608-01 PURPOSE

01.01 To provide guidance on the implementation of the operating Reactor Oversight Process (ROP) performance indicator program. Additionally, this manual chapter provides guidance on the process for modifying existing performance indicators (PIs) and developing additional PIs for use in the oversight process.

0608-02 OBJECTIVE

02.01 To give guidance for implementation of the PI program, including collecting and posting PI data on the internal and external web-page.

02.02 To provide additional guidance on implementing the PI verification inspection procedure.

02.03 To provide a process to resolve PI interpretation issues.

02.04 To provide a process to develop new PIs or to make changes to existing PIs including any thresholds.

0608-03 APPLICABILITY

This manual chapter applies to all operating commercial nuclear power reactors.

0608-04 DEFINITIONS

Change. A modification to an existing PI or threshold result in the licensee making a change to its procedures or PI data collection or reporting process in an effort to implement the change.

Discrepant Performance Indicator Data. PI data reported by a licensee that either (a) is not in accordance with the applicable version of NEI 99-02, "Regulatory Assessment Performance Indicator Guidelines," and applicable Frequently Asked Questions (FAQs) on the NRC's external world wide web site; (b) has major discrepancies; or (c) causes the NRC to lose confidence in the licensee's ability to collect and report PI data accurately. Situations that may result in (c) above include, but are not limited, to the following:

(1) recurring discrepancies in the reported data
(2) recurring instances of incorrect interpretations of NEI 99-02
(3) inadequate documentation of PI data

Attachment 9

Extended Shutdown. For the purposes of the ROP PI Program, when a reactor has no critical hours for two consecutive quarters.

Frequently Asked Question (FAQ). A question raised by a stakeholder related to ROP PIs. When an answer to a FAQ has been approved, the term FAQ refers to both the question and its approved answer. FAQs are maintained in a database on both the NRC's internal and external web sites. Those sites are periodically updated to include new FAQs without approved answers as well as FAQs that have been approved for use. FAQs can be viewed by cornerstone/PI, posting date, or identification number.

Interpretation Issue. When a licensee and the region disagree on what should be reported or the licensee and regional NRC staff have conflicting understandings of the intent of any part of NEI 99-02, "Regulatory Assessment Performance Indicator Guidelines."

Major Discrepancy. When a licensee reports incorrect data that affects the NRC's response in accordance with the Action Matrix (IMC 0305, "Operating Reactor Assessment Program") because correction of the discrepancy results in a PI exceeding a threshold.

Recurring Discrepancies. After the Program Office has clarified an issue, the licensee continues to report the same or similar discrepancy.

Unintended Consequences. Undesirable consequences (i.e. unsafe plant conditions, misinterpretation of PI) resulting from actions taken in response to PIs or PI reporting criteria.

Unreported Data. When a licensee does not report data an applicable PI.

0608-05 RESPONSIBILITIES AND AUTHORITIES

05.01 Director, Office of Nuclear Reactor Regulation (NRR)

a. Oversees development and implementation of policies, programs, and procedures for the performance indicator program.

b. Oversees assessment of the effectiveness and implementation of the performance indicator program.

05.02 Chief, Inspection Program Branch

a. Develops policy, programs, and procedures for the PI program

b. Assesses PI program effectiveness and implementation.

c. Receives PI data and makes updates to the internal and external web sites.

d. Resolves interpretation issues.

e. Updates the FAQ database on the NRC's internal and external web sites.

f. Implements changes to existing PIs or thresholds as appropriate.

draft

g. Develops new PIs.

05.03 Regional Administrator

Ensures the implementation and use of PIs as a part of the ROP in accordance with MD 8.13, "Reactor Oversight Process," Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," Inspection Procedure (IP) 71151, "PI Verification," and IP 71150, "Discrepant or Unreported Performance Indicator Data."

0608-06 BACKGROUND

06.01 Framework

The ROP is built upon a framework directly linked to the Agency's mission. That framework includes cornerstones of safety that (1) limit the frequency of initiating events; (2) ensure the availability, reliability, and capability of mitigating systems; (3) ensure the integrity of the fuel cladding, the reactor coolant system, and containment; (4) ensure the adequacy of the emergency preparedness functions; (5) protect the public from exposure to radioactive material releases; (6) protect nuclear plant workers from exposure to radiation; and (7) provide assurance that the physical protection system can protect against the design-basis threat of radiological sabotage.

Within each cornerstone, a broad sample of data on which to assess licensee performance in risk-significant areas is gathered from PI data submitted by licensees and from the NRC's risk-informed baseline inspections. The PIs are not intended to provide complete coverage of every aspect of plant design and operation, but are intended to be indicative of performance within the related cornerstone.

Data submitted by each licensee is used to calculate the PI values, which are then compared to risk-informed, objective thresholds. The "green" coding indicates performance within an expected performance level in which the related cornerstone objectives are met; "white" indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met; "yellow" indicates related cornerstone objectives are being met, but with minimal reduction in safety margin; and "red" indicates a significant reduction in safety margin in the area measured by that performance indicator..

06.02 Performance Indicators

The PIs are a means of obtaining information related to the performance of certain key attributes in each of the cornerstone areas. They provide indication of problems that, if uncorrected, may increase the probability of risk or consequence of an event. Since not all aspects of licensee performance can be monitored by PIs, the risk-significant areas not covered by PIs will be assessed through inspection.

A. For the reactor safety area, the cornerstones and PIs are as follows:

Initiating Events - this cornerstone is intended to limit the frequency of those events that upset plant stability and challenge critical safety functions during shutdown as well as

power operations. Such events include reactor trips due to turbine trips, loss of feedwater, loss of off-site power, and other reactor transients. The following indicators are provided in this cornerstone:

- Unplanned scrams (automatic and manual) per 7,000 critical hours
- Scrams with loss of normal heat removal per 12 quarters
- Unplanned power changes per 7,000 critical hours

Mitigating Systems - this cornerstone is intended to ensure the availability, reliability, and capability of systems that mitigate initiating events to prevent reactor accidents. Mitigating systems (both operating and shutdown events) include those systems associated with safety injection, residual heat removal, and their support systems, such as emergency AC power. The following indicators are provided in this cornerstone:

- Safety System Unavailability - this performance indicator is calculated separately for each of the following four systems for each reactor type:

  BWRs
  - emergency AC power systems
  - high pressure injection systems (high pressure coolant injection, high pressure core spray, or feedwater coolant injection)
  - residual heat removal systems
  - heat removal systems

  PWRs
  - emergency AC power systems
  - high pressure safety injection systems
  - residual heat removal systems
  - auxiliary feedwater systems

- Safety System Functional Failures

Barrier Integrity - this cornerstone is intended to ensure the integrity of the physical barriers designed to protect the public from radionuclide releases caused by accidents. These barriers are the fuel cladding, reactor coolant system boundary, and containment. The following indicators are provided in this cornerstone:

- Reactor Coolant System (RCS) Specific Activity
- RCS Identified (or total) Leak Rate

Emergency Preparedness - this cornerstone is intended to ensure that actions taken in accordance with the emergency plan provide adequate protection of the public health and safety during a radiological emergency. The cornerstone does not include off-site actions, which are covered by the Federal Emergency Management Agency. The following indicators are provided in this cornerstone:

- Drill/Exercise Performance
- Emergency Response Organization Drill Participation
- Alert and Notification System Reliability

B. For the radiation safety area, the cornerstones and PIs are as follows:

Occupational Radiation Safety - this cornerstone is intended to ensure adequate protection of worker health and safety from exposure to radiation and radioactive materials during routine civilian nuclear reactor operations. The following indicator is provided in this cornerstone:

- Occupational Exposure Control Effectiveness

Public Radiation Safety - this cornerstone is intended to ensure adequate protection of public health and safety from exposure to radioactive materials released into the public domain as a result of routine civilian nuclear reactor operations. These releases include routine gaseous and liquid radioactive effluent discharges, the inadvertent release of solid contaminated materials, and the offsite transport of radioactive materials and wastes. The following indicator is provided in this cornerstone:

- Radiological Effluent Technical Specifications (RETS)/Offsite Dose Calculation Manual (ODCM) Radiological Effluent Occurrences

C. For the safeguards area, the cornerstone and PIs are as follows:

Physical Protection - this cornerstone is intended to provide assurance that the physical protection system can protect against the design basis threat of radiological sabotage. The threat could come from either external or internal sources. The following indicators are provided in this cornerstone:

- Protected Area Security Equipment Performance Index
- Personnel Screening Program Performance
- Fitness-for-Duty (FFD)/Personnel Reliability Program Performance

0608-07 PI DATA SUBMISSION

Reporting of PI data to the NRC is a voluntary program in which all licensees participate. Historical data necessary to begin the program was submitted on January 21, 2000, using the guidelines of Regulatory Issues Summary 00-08, "Voluntary Submission of Performance Indicator Data," and NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 0. NEI 99-02 contains the general reporting guidelines used by the licensee to report PI data to the NRC. In accordance with NEI 99-02, quarterly PI data will be submitted to the NRC within 21 days following the end of the reporting period. The program began on April 2, 2000, and the first submission of PI data for all operating reactor plants occurred on April 21, 2000.

To submit PI data, licensees send a delimited text file to a central NRC e-mail address - pidata@nrc.gov. Hard copy submissions, in accordance with 10 CFR 50.4 "Written Communications," are not required, except in the event that the e-mail system fails. Within 2 business days of receipt of the PI data, the NRC will send each licensee a return e-mail with its submission attached to confirm and authenticate receipt of the data. The licensee has four business days from receipt of the NRC's e-mail to report any transmission problems to the NRC.

Once the data is confirmed by the NRC, it is entered into the Reactor Program System database to calculate the indicator values. Within five business days from receipt of the licensees' data transmissions, the NRC will post the data, the indicator values, and associated graphs on the NRC's internal web site. The regions will be notified by e-mail that the PIs are available on the internal web site. This is to allow the regions an opportunity to become familiar with the PIs and to identify any obvious errors prior to public release. Within 10 business days of receipt of the licensees' data transmittals, the NRC will place the PIs on the NRC's external web site to make them available to external stakeholders.

07.01 Extended Shutdown

An operating commercial nuclear power plant with performance or major equipment problems may be shut down for an extended period of time for a variety of reasons. Licensees may voluntarily or involuntarily shut down the plant due to significantly degraded performance, major equipment failures, or a significant plant event. In these cases, Inspection Manual Chapter 0350, "Staff Guidelines For Assessment and Review Of Plants That Are Not Under The Routine Reactor Oversight Process," should be followed.

For the purposes of the ROP, a plant is in an extended shutdown when it has no critical hours for two consecutive quarters. In such a situation, the Initiating Events PIs provide no relevant information and need not be reported. The Mitigating Systems and Barrier PIs may provide information, depending upon plant activities and schedules, and should be reported as appropriate. The Emergency Preparedness, Occupational Radiation Safety, Public Radiation Safety, and Physical Protection PIs will continue to provide pertinent information and should be reported every quarter.

Upon recovery from an extended outage, licensees should report Initiating Events PIs after the first full quarter of operation. Mitigating Systems and Barrier PIs should be reported upon startup. Emergency Preparedness, Occupational Radiation Safety, Public Radiation Safety, and Physical Protection PIs should be reported every quarter, regardless of plant mode.

0608-08 PI VERIFICATION

PI data must be reported accurately because it is used by the NRC to make decisions regarding agency actions in the assessment process. Inspection Procedure 71151, "Performance Indicator Verification," shall be followed to regularly review a licensee's PI data collection and reporting activities, for adherence to pertinent guidance and data accuracy and completeness. Discrepancies with the performance indicator data collection and reporting or the actual data should be documented in accordance with Section 02.03 of IP 71151.

When the ROP first implemented, TI 144, "Performance Indicator Data Collecting and Reporting Process Review," was developed to provide a one-time verification that each reactor site has an established process to collect and report the PI data accurately. Upon expiration of TI 144, this IMC provides the guidance for the continuing PI data collection, reporting, and verification processes. Regional management should coordinate its activities in this area with IIPB's Performance Assessment Section.

In preparation for initial implementation, licensees compiled and submitted at least 4-quarters worth of historical data. This was done as a "best effort" to construct a basis from which to provide initial PI values. In recognition that licensees conducted a best effort to review historical data and that some errors could result, the NRC elected to, for the historical data submission, exercise enforcement discretion, in accordance with Section IX, "Inaccurate and Incomplete Information," of the "General Statement of Policy and Procedure for NRC Enforcement Actions." The NRC will continue this discretion during initial implementation of the ROP until January 31, 2001. Therefore, when reporting inaccuracies are identified during this period, the regions should not cite a level IV violation in accordance with 10 CFR50.9, "Completeness and Accuracy of Information."

08.01 Discrepant or Unreported PIs

When PI data has been determined to meet any of the definitions for discrepant or unreported data contained in Inspection Procedure 71150, "Discrepant or Unreported Performance Indicator Data," that procedure should be followed. The selection of inspections to compensate for the discrepant or unreported PI data will be determined by regional management. Regional management should coordinate its activities in this area with IIPB's Performance Assessment Section. The selected inspections will be performed in addition to the baseline inspection. Once the licensee has corrected the root cause(s) of the discrepant or unreported data, and the NRC has verified that the licensee can collect and report PI data accurately, IP 71151 will be used for subsequent PI verification inspections.

0608-09 QUESTIONS AND FEEDBACK

Indicators are new to the reactor oversight process. They play a major role in gathering information to assess licensee performance. Questions regarding their application from internal and external sources are anticipated. Also, as NRC and industry gain experience with the PI program and the ROP, changes to an existing PI and its thresholds, as well as development of new PIs, are expected. Further incremental changes will be necessary to respond to lessons learned during implementation of the ROP.

NRC has established a formal process to (1) address questions and feedback from internal and external stakeholders, (2) make changes to existing PIs and thresholds based on lessons learned, and (3) develop new PIs and associated thresholds. This formal process, PI Process For Addressing Feedback and Questions (Exhibit 1), has four major components to respond to feedback and questions. These include: input, evaluation, resolution, and close-out.

The remainder of this IMC describes the formal process. Exhibit 1 should be referred to when applying the steps of the process.

09.01 Input

Questions are raised by NRC staff, industry, or the public. When NRC personnel raise a question the guidance in this manual chapter should be followed. Industry should submit questions to an NEI representative, such that it will be addressed at periodic public meeting held between the NRC and NEI. Questions raised by the public should continue to follow the

normal process that has been used to submit inquires to the NRC. If appropriate, the NRC staff will initiate an internal feedback to ensure an issue raised by the public is formally captured in the NRC's, interview process for PI issue resolution.

When an NRC staff member has a question about a PI definition, intention, or application arises, the frequently asked question (FAQ) database should be checked for existing guidance. If the question has not previously been addressed a feedback form, Exhibit 2, must be filled out. Additionally, a PI Feedback Form can be down loaded from the internal ROP web page http://nrr10.nrc.gov/NRR/ROP_DIGITAL_CITY/ROP_digital_city.html , which is linked to the Program Development icon.

If the originator is knowledgeable about the issue, a proposed resolution can be included in the region's interpretation section of the form. Regional management on the branch chief level should approve the interpretation request and forward the completed form to the PIISSUES mailbox. However, the completed form can be mailed to the branch chief of IIPB.

Once the form has been received, IIPB will forward a reply to the originator within 7 business days, to acknowledge receipt of the form, and to inform the originator of the PI tracking number and the lead reviewer assigned to resolve the issue. All follow-up questions should be directed to the lead reviewer assigned to resolve the issue. Questions received from the public will be addressed through formal correspondence and tracked using IIPB's internal PI Tracking System.

09.02 Evaluation of Questions/Feedback

Each issue will be initially screened when received by IIPB. Those issues not requiring further clarification will be immediately resolved. IIPB will respond via e-mail to the originator and the issue will be closed out in the PI tracking system.

Issues that require clarification in meaning or intent will result in clarifications without changes. "Resolutions of Questions and Feedback not Requiring a PI Change," (Section 9.03), will be followed to address the question.

Issues that require a new PI or a change to an existing PI or threshold will be evaluated for feasibility. "Resolutions of Questions and Feedback Requiring a PI Change," (Section 9.04), will be followed to address the question. The evaluation will also consider if the proposed change can be justified. If the proposed change cannot be justified, a response with the details will be forwarded to the originator and will be closed out in the PI Tracking System.

09.03 Resolution of Question/Feedback Not Requiring A Change

Resolution of this type consists of the implementation of a series of actions to address the questions/feedback. The following steps will be performed to complete the response to this type of issue:

a. IIPB will develop the proposed response (if the originator is knowledgeable about the issue, insights should be included in the resolution section of the interpretation form). The response and corresponding question will become an FAQ. IIPB will involve the appropriate regions and NRR technical staff when developing the official response.

b. NRC and NEI will discuss the issue and proposed response in a public meeting. NEI will enter the new FAQ into a running log that contains draft FAQs (both generated by NRC and external stakeholders). New issues pending resolution will also be made available on the ROP internal and external web pages.

c. NRC and NEI will approve the proposed FAQ and develop an appropriate response in a public meeting, which incorporates active participation from all stakeholders in attendance. This portion of the process is iterative and could take several working meetings to reach a resolution. The goal is to arrive at an approved response by the close of the meeting in which the issue is first discussed. However, there are instances when NEI elects to defer the topic until the next public meeting, such that its experts can review and comment on the NRC's proposed solution. When all views are presented and discussed and an alignment is still not achieved, NRC will make the final decision.

d. NEI will update the FAQ log to reflect preliminarily approved responses and transmit the FAQ log to NRC electronically. NRC will place the FAQs on the internal web for regional review. After a two week review period for regional management, IIPB will review and incorporate the regional feedback. If a change occurs, another public meeting will be scheduled to discuss the final proposed change. Upon completing the official agency response, IIPB will first place the approved FAQs on the internal web for two days to solicit regional comments before making it available to the public. After this waiting period, IIPB will place the approved FAQs in the external web approved FAQ file. NEI will notify the licensee of the updated FAQ. IIPB will notify appropriate internal stakeholders of the resolution.

e. NEI 99-02 will be updated periodically to incorporate approved FAQs.

During the time that it takes to resolve an interpretation issue associated with a PI inspection related issue, inspectors shall document this as an unresolved item in accordance with 0610* "Power Reactor Inspection Report," section 06.04a, Initiating Opening Items.

09.04 Resolution of Question/Feedback Requiring A Change

Questions that require more than clarification in meaning, intent, or explanation, will involve a series of actions to make a change to the PI. IIPB evaluates the issue for feasibility and the ability to improve the efficacy of the existing PI/ threshold, and provide information regarding key attributes not currently monitored. Resolution may involve creating a new PI, changing an existing PI, changing a threshold for an existing PI, or changing an existing PI to reflect a unique (plant design) features. Each of the processes share common steps, but will be discussed separately.

Prior to expending resources, IIPB will reach a determination as to whether or not the proposed change can be justified. For those changes that would clearly not be feasible, a response, including a rationale for not proceeding, will be forwarded to the originator and the issue will be closed-out.

If the issue is justifiable, the change process will begin in accordance with the appropriate type of change:

a. New PI

When the desired performance is not being measured by an existing PI there may be a need to create a new PI. In creating a new PI, key attributes of performance which the NRC needs to assess to ensure that the cornerstone objectives are met must be identified in accordance with pertinent information contained in the introduction of SECY 99-007, section 2, "Framework Development Process." Once the framework for creating a new PI has been identified and technically justified, a new PI or alternative solution will be developed.

Prior to performing the tasks to develop the new PI, the OMB clearance status shall be verified as current. The OMB clearance used for the pilot program is applicable for three years and allows additional PIs to be added when necessary. Thereafter, it is required to be updated by the Office of Chief Information Office, Records Management Branch. Subsequent PIs must be treated the same way.

When the new PI has been created, regional insights gained through field experience also need to be factored into the development of the PI. Regional management will be given 21 days to provide IIPB with comments. These comments will be incorporated to assist in the agency's proposal of the new PI when presenting it to the industry in a public meeting.

Public meetings are then held between NRC and NEI to discuss the proposed PI. A meeting notice is sent out to notify the public of this meeting, and to solicit participation from any interested stakeholders. This portion of the process is iterative and could take several working meetings to reach a resolution.

After NRC has considered public comments and industry concerns, NRC will continue in the process to collect historical data, if available, and establish thresholds (See Section 3, Change Thresholds). If such data is not available, a panel of NRC experts representing the respective PI area will be assembled to establish the threshold(s). These results will be benchmarked to validate the PI by comparing the PI against performance. Benchmarking determines if the PIs can (1) differentiate between plants perceived as superior, average, declining, and poor performers, and (2) identify declining performance in a timely manner so that increased regulatory attention can be applied before performance becomes unacceptable. If a correlation exists, it will be considered a good indicator; if not, it may still give insights that reveal that the plant is a poor performer, relative to the results of other correlations.

Changes to the baseline inspection program are identified in accordance with IMC, 0040, "Preparing, Revising, and Issuing Documents for the NRC Inspection Manual," during the time it takes to propose the solution and benchmark the new PI.

Next, a sample of plants reflecting a cross section of industry representatives with the common issue under review is selected. (Typically, there are two situations that require newly formed pilot size: new PIs and site-specific concerns) This sample constitutes plants that will voluntarily test the PI for the duration of the pilot program. It will be piloted for 3 - 6months to observe effectiveness and potential weaknesses. Simultaneously, during the pilot program, a Federal Register Notice is sent out to notify the public of this meeting, and to solicit participation from any interested stakeholders.

When the pilot program has been completed, feedback and lessons learned gained from the pilot program will be incorporated into the ROP via the "Process For Addressing Questions and Feedback." NEI 99-02 will be updated to reflect the change in a future revision. Other sources of feedback include the public, industry, NEI, special interest groups, internal NRC staff, etc.

This cyclic evolution of collecting and testing data, then incorporating improvements into the PIs is by design. This was the original philosophy (See SECY 99-007, "Recommendations For Reactor Oversight Process Improvements) adopted during the inception phase of the ROP.

Once the PI has been developed and piloted, lessons learned incorporated, and public comment addressed, training sessions and workshops may be held in each region, if appropriate. Both industry and regional representatives will attend the workshops. Training may be delayed if the PI can be communicated by other means. Also, alternate means of communication may be utilized in lieu of workshops and training, such as Regulatory Guides, NUREGs, etc., to provide guidance to stakeholders. In the case of newly developed risk-informed PIs, training and workshops will be given to accommodate the developmental rate.

IIPB will issue a Regulatory Information Summary (RIS) to inform stakeholders of the new PI change. The RIS will be forwarded to the regional Directors of Reactor Projects, Reactor Safety, and Plant Support; inspectors; and NEI. Additionally, the RIS will be placed in NRC's Public Document Room and on the external web-site, http://nrr10.nrc.gov/NRR/OVERSIGHT/ASSESS/INDEX.html. , which can be accessed from the Inspection Manual of Agency Wide Applications. Additionally, IP 71151 will be revised to reflected the new PI.

b. Change PI

Changing a PI is very similar to creating a new PI. Like the initial steps in creating a new PI, the key attributes which the NRC needs to assess to ensure that the cornerstone objectives are met and captured in the change are identified from the framework described in SECY 99-007. When IIPB has developed a proposed change to the PI, it will be provided to the regions. Regional management will be asked to provide comments within 21 days.

A series of public meetings will be held to discuss the proposed change. This iterative process allows all stakeholders an opportunity to contribute to the resolution and consider other proposed alternatives. After the public meeting, where the proposed change is approved, new data will be collected if necessary and thresholds established accordingly. In some cases, historical data may need to be collected. Thresholds will be established with the new data and the guidance on Bench marking, and subsequent steps contained in the New PI section will be followed until the change is completed.

If new data is unnecessary, thresholds will be established and the guidance on Bench marking and subsequent steps contained in the New PI section will be followed until the change is completed.

c. Change Threshold

Changes to thresholds may be necessary when surrogate data was used in lieu of actual data to establish many ROP PI thresholds. New thresholds, on the other hand, are established when a new PI is created.

Several thresholds for the PIs were established with the best available data offered by the licensees that participated in the piloting of the ROP. As the ROP progressed into initial

implementation, real data became available to establish thresholds reflecting actual industry performance.

As experience is gained from the ROP, NRC will continue to monitor industry performance against pre-established thresholds. Following initial implementation, some thresholds may need to be adjusted to better reflect actual industry performance. This practice of threshold adjustments is not intended to change performance expectation, but rather to accurately reflect the experience and insights gained from the ROP.

When a threshold is changed or established, it is intended to accurately reflect industry performance as reflected by the data collected and analyzed. If applicable, risk analysts from NRC and NEI will collaborate with IIPB and NEI representatives, respectively, to factor in those scenarios which are most risk significant to the PI under review.

When setting performance thresholds, risk and regulatory response to different levels of licensee performance will be considered. If there are instances that the PI threshold cannot be directly tied to probabilistic risk assessment data it will be linked to regulatory requirements or professional judgement of the NRC staff and nuclear industry.

These results will be benchmarked (See New PIs for details) to validate the PI. Upon validation, stakeholder input is solicited for incorporation into the proposed solution. There is a 21-day waiting period to obtain feedback from internal stakeholders. An NRC/NEI public meeting is then held to discuss the proposed solution. Once the new threshold has been approved by the NRC, it will be incorporated into the next updated version of NEI 99-02 to reflect the changes.

IIPB will issue a Regulatory Information Summary to inform stakeholders of the new PI change. The RIS will be forwarded to the regional Directors of Reactor Projects, Reactor Safety, and Plant Support; inspectors; and NEI. Additionally, the RIS will be placed in NRC's Public Document Room and on the external web-site, http://nrr10.nrc.gov/NRR/OVERSIGHT/ASSESS/INDEX.html., which can be accessed from the Inspection Manual of Agency Wide Applications. Additionally, IP 71151 will be revised to reflected the changed PI.

d. Unique PI

With 103 reactors and 4 owners groups, there are unique design features which may not strictly comply with the data reporting elements required in the indicator value calculations outlined in the PI reporting guidelines of NEI 99-02.

In such cases, a newly formed sample size representing those plants with unique differences from the established guidelines may be required. Site-specific PIs include all of those plants, with unique circumstances (i.e., plant design) differing from the majority of the industry, which cannot comply with NEI 99-02 reporting guidelines.

Rather than IIPB proposing a solution as with a new or changed PI, an NRC/industry working group will be formed to develop a common solution and collect germane data from all affected licensees. If historical data is available, it will be collected. When historical data is unavailable an expert panel will be assembled to provide data gained from experience and knowledge.

After historical data is gathered, new thresholds are established and the results are benchmarked. The NRC will then follow the remainder of the guidance outlined in Section c, Change Threshold, to complete this process.

Close-Out

For the purposes of this manual chapter, this section will address only the closure of those issues that enter the change process through the PI Tracking System, via feedback form. Upon resolution of an issue, the completion date will be entered into the PI tracking system. An e-mail response will be forwarded to the originator within 7 business days of IIPB reaching a resolution representing the official agency response. This action will close the item out. If the originator is not satisfied with the resolution, the originator should submit a new feedback form that describes the new concern and reference the previous tracking number.

0608-10 PI REFERENCES

Management Directive 8.13, "Reactor Oversight Process"

SECY-99-007, "Recommendations For Reactor Oversight Process Improvements"

SECY-99-007A, "Recommendations For Reactor Oversight Process Improvements (Follow-up to SECY-99-007)"

SECY-00-049, "Results Of The Revised Reactor Oversight Process Pilot Program"

Temporary Instruction 2515/144, "Performance Indicator Data Collecting and Reporting Process Review"

Inspection Procedure 71151, "Performance Indicator Verification"

Inspection Procedure 71150, "Discrepant or Unreported Performance Indicator Data"

Regulatory Information Summary 99-06, "Voluntary Submission Of Performance Indicator Data" (collecting and reporting historical data)

Regulatory Information Summary 2000-08, "Voluntary Submission Of Performance Indicator Data" (collecting and reporting data reflecting plant performance during full implementation of revised reactor oversight process)

General Statement of Policy and Procedure for NRC Enforcement Actions

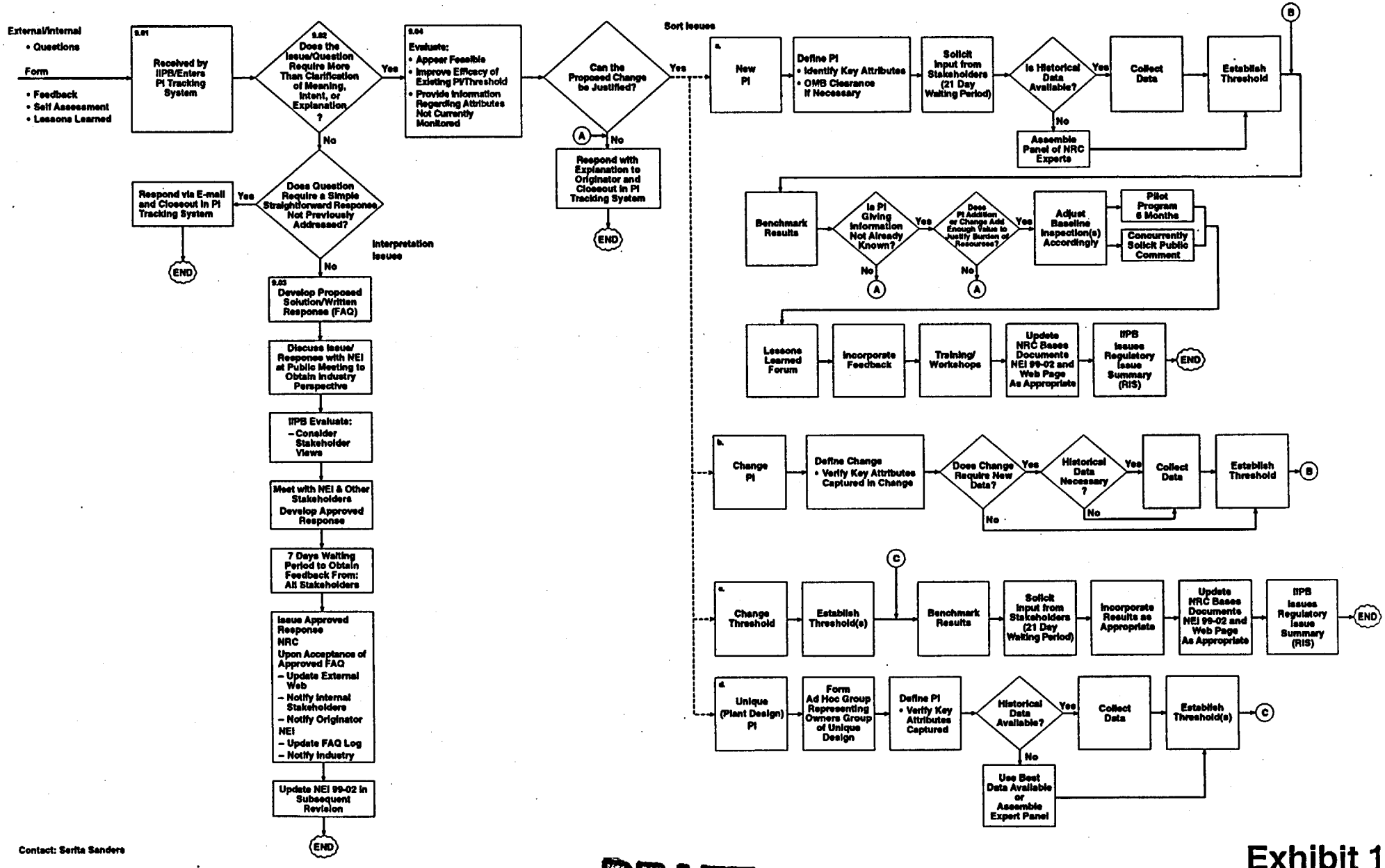
Manual Chapter 0350, "Staff Guidelines For Assessment and Review Of Plants That Are Not Under The Routine Reactor Oversight Process"

Web-site For Frequently Asked Questions: http://NRR/OVERSIGHT/ACCESS/FAQs_by_pi_pdf

ROP Web-site: http://nrr10.nrc.gov/NRR/ROP_DIGITAL_CITY/ROP_digital_city.html

Draft

PERFORMANCE INDICATORS
Process for Addressing Questions and Feedback



Contact: Serita Sanders

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Exhibit 1

PERFORMANCE INDICATOR FEEDBACK FORM

Instructions: Fill out the form and send it to NRR/IIPB through regional DRP branch chief via e-mail to "PIISSUES". A hard copy of the form, including the regional branch chief review, can also be provided to chief, IIPB.

Document No.: _____ Attachment No. (if applicable): _____

Topic:

Inspection	☐	SDP	☐	PIs	☐
Assessment	☐	Enforcement	☐	Other	☐

General:

1. Clarity: Are the requirements and guidance clear and understandable?

Inspection:

1. Statement of Problem:

Comments/Recommendations: (If this is a PI interpretation concern, first state the licensee's interpretation, then the region's position. Recommendations are also welcome.)

Originator:

Name/Email: _____ Phone No.: _____ Region/Div: _____

Plant Name (if applicable): _____

Date Submitted: _____

draft

Regional Review:

Reviewed by: _____

Regional Action:

Respond ☐ Send to IIPB ☐

Remarks:

_____

IIPB Lead Reviewer:

IIPB Contact:
Name/Email: _____ Phone No.: 301-415-_____

Date Received: _____

Date of Initial Action: _____

Initial Action (place details in Remarks, below):

IIPB Resolution:

Date of Final Action: _____

IIPB Section Chief Approval: _____

Final Action (place details in Remarks, below):

Remarks:

draft

Exhibit 2

FAQ Review Results From 9/20 9/21 Public Meeting

FAQ	Status from 9/20 – 9/21 public Meeting
8.22	Tentative Approval (Awaiting final approval)
8.24	Tentative Approval (Awaiting final approval)
9.5	Approved, Post date 10/1/00
10.4	Withdrawn
10.7	Withdrawn
11.3	Approved, Post date 9/21/00
11.4	Approved, Post date 9/21/00
11.5	Withdrawn
11.6	Approved, Post date 10/1/00
11.7	Tentative Approval (Awaiting final approval)
11.8	Tentative Approval (Awaiting final approval)
11.9	Tentative Approval (Awaiting final approval)
11.10	Tentative Approval (Awaiting final approval)
11.11	Tentative Approval (Awaiting final approval)
11.12	Tentative Approval (Awaiting final approval)
11.14	Tentative Approval (Awaiting final approval)
11.15	Tentative Approval (Awaiting final approval)
11.18	Approved, Post date 10/1/00
12.1	Approved, Post date 10/1/00
12.2	Approved, Post date 10/1/00
12.6	Tentative Approval (Awaiting final approval)
12.7	Withdrawn
13.3	Tentative Approval (Awaiting final approval)
13.4	Tentative Approval (Awaiting final approval)

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Attachment 10

FAQ Log 8				
Temp No.	PI	Question/Response	Status	Plant/ Co.
15.	MS02	**Question:** Our HPSI system is similar to that depicted in Figure 5.2 of NEI 99-02, consisting of two independent trains, as defined NEI 99-02 for monitoring purposes. Each train consists of one HPSI pump and the associated train related valves and piping. Each pump is able to take a suction from the Refueling Water Tank (RWT) or Containment Sump (CS), and inject into the RCS through four cold leg injection flow paths and one hot leg flow path. Each cold leg flow path includes one motor operated isolation valve and an isolation check valve. These flow paths, four each for the two independent trains, then converge into four common headers that flow to the RCS. Flow may be split between the train related cold legs and the associated hot leg later into an event when necessary to preclude boron precipitation in the core. We are performing an analysis to demonstrate that injection flow, sufficient to satisfy the requirements of the safety analysis, can be achieved by either train with one of its four cold leg injection paths out of service. Is it acceptable, in the assessment of NEI 99-02 availability, to employ realistic component performance assumptions in a system level analysis, or is the utility required to use all design basis assumptions, consistent with those used in the associated safety analysis. **Alternate Question:** Is it acceptable, in the assessment of NEI 99-02 availability, to employ realistic component performance assumptions in a system level analysis, or is the utility required to use all design basis assumptions, consistent with those used in the associated safety analysis?	Discussed 6/14/00 Revised 6/14/00 Action: NEI discuss revised response with APS 7/11/00 – awaiting response from APS 7/12/00 – Discussed, on hold 8/2 – Alternate question and response provided by NRC 9/20 – Obtain clarification on assumptions being used by APS (SK)	APS
		Response: Fault exposure unavailable hours are not counted for a failure to meet design or technical specifications, if engineering analysis determines the train was capable of performing its safety function during an operational event. The engineering analysis must take into account other equipment deficiencies that existed at any time during the failure to meet design or technical specification requirements, and must assume the worst case accident for the plant conditions. However, it is not necessary to assume an independent single failure and the analysis can assume nominal (expected) performance of other plant equipment. System unavailability is not subject to the same analysis requirements as the corresponding 10CFR50 Appendix K safety analysis. **Alternate Response:** Guidance on operability determinations and the resolution of degraded and nonconforming conditions is provided in Generic Letter 91-18. However, for the purposes of the safety system unavailability indicator, each train of a system must be capable of meetings all of its design basis requirements. To demonstrate that a train is available, then, requires that all design basis assumptions used in the FSAR safety analyses be employed.		

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FAQ Log 8

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.	MS04	**Question:** **Appendix D Indian Point 2, Indian Point 3** The ECCS designs for Indian Point 2 and Indian Point 3 include two recirculation pumps, recirculation containment sump, piping and associated valves located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to RHR), two RHR heat exchangers and associated valves. These two subsystems are identified in the Technical Specifications and FSAR. The RHR/LHSI system is automatically started on an SI, takes suction from the RWST as does the high head SI pumps (3), and provides water in the injection phase of an accident. The recirculation pumps are in standby in the injection phase and are actuated by operator action during switchover for the recirculation phase of an accident and RHR is put in standby. The recirculation pumps (2) take suction from its dedicated sump and have the capability to feed the containment spray system, low head injection lines and the suction of the high head SI pumps for high head injection. The recirculation pumps are inside containment and can not be tested during operation, but both are required to be operable above 350 degrees F and one above cold shutdown. How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR. **Response:**	Discussed with IP2, IP3, NRC in 8/28 conf. call.	IP3
22.	MS04	**Question:** Function 2 of the RHR Performance Indicator monitors the ability to remove decay heat during a normal heat unit shutdown. The 2 SDSC HX's at Calvert Cliffs are supplied RCS fluid by 2 SDC pumps via a common suction and common discharge header (not single failure proof). The SDC HX's are cooled by the Component Cooling (CC) Water system. The CC system is a closed system that exchanges heat to the Salt Water system via two parallel heat exchangers (CCHX). Component Cooling is always operated cross tied before and after the CCHX's. When one of the two SW trains is removed from service only one CCHX is available. Two saltwater pumps, with independent power, are available as well as 2 component cooling water pumps with independent power. In Mode 5, RCS Loops filled, Technical Specification LCO (old: TS 3.4.1.3; ITS: 3.4.7) requires 2 SDC loops (one operable and one in operation assuming no S/G's available). We consider that one SDC loop is unavailable (SDC HX's and SDC pumps) if one Salt Water train is removed from service. Is this a proper interpretation of NEI 99-02 guidelines? **Response:** Yes. Assuming the Salt Water System is a necessary support system, and the Salt Water System can provide the cooling for Component Cooling sufficient to remove heat for one loop of SDC. However, when one train of the Salt Water System is removed from service, you no longer meet the "Support System Unavailability" guidance of NEI 99-02 for not reporting unavailable hours. In this situation you are required to report unavailable hours for one train of the monitored system (i.e., SDC.), since one loop of SDC is available and in operation and the other loop cannot be made available without removing heat removal capability from the operating loop of SDC. If, however, the remaining Salt Water System train is capable of satisfying the heat removal requirements of both trains of SDC, no SDC unavailability would be reported.	On hold. K. Borton to discuss with CC 8/3/00 – NEI revision of questionand proposed response. 9/20 – Tentative Approval	Calvert Cliffs
24.	MS04	**Question:** Are there times when RHR Shutdown Cooling can be removed from service without incurring unavailable hours, if allowed by Technical Specifications (i.e., reactor level and temperature requirements met).	Revised 6/13/00 Discussed 6/14/00 Action: NRC to	Duane-Arnold

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FAQ Log 8

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: Yes. Unavailable hours are counted only for periods when a train is required to be available for service. However, Technical Specifications that require one subsystem remain operable and in operation above a specified temperature would be counted if one subsystem were not available or an alternate method (normally specified in the Technical Specification Action Statement) were not available. ~~See FAQ ID 17.~~	discuss with Residents 8/29 – NEI Suggestion to remove "See FAQ ID 17" 9/19- NEI revision 9/20 – Tentative Approval	

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FAQ Log 9

Temp. No.	PI	Question/Response	Status	Plant/ Co.
9.2	MS01 MS02 MS03 MS04	**Question** NEI 99-02 Revision 0 defines criteria for determining availability during surveillance testing. This definition can be found on page 26. It allows operator action to be credited for the declaration of availability. NEI 99-02 also defines criteria for determining fault exposure. This definition can be found on pages 28 & 29. Line 5, page 29 references operator action. It states, "Malfunctions or operating errors that do not prevent a train from being restored to normal operation within 10 minutes, from the control room, and that do not require corrective maintenance, or a significant problem diagnosis, are not counted as failures." In addition, page 29, line 13, states, "A train is available if it is capable of performing its safety function." If the fault can be corrected quickly (much less than 10 minutes) by a single operator action that is contained in a written procedure, is uncomplicated, and does not require diagnosis or repair, but the operator action cannot be shown to satisfy auto-start time design assumptions (e.g., HPCI injection within 45 seconds), should fault exposure hours be assigned to a failure?	7/12/00 – NRC action to confirm consistency with MR and expand upon response. 8/2/00 NRC revision to proposed response. 8/29 NEI Alternate response added. 9/20 – Discussed. On hold, NRC to continue review.	ComEd
		Response Operator actions to restore a train to normal operation following a malfunction cannot be credited for any purpose. A failure would be reportable per 10 CFR 50.72(b)(2)(iii) and 50.73(a)(2(v); it would be considered a maintenance-preventable functional failure; it would be counted as a demand and a failure in PRA applications; and it would counted in the performance indicators as both a safety system functional failure and a period of unavailability (if it resulted in failure of one of the four monitored functions). Operator actions to recover from an operating error could be credited if the function can be promptly restored from the control room by an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e., the restoration actions are virtually certain to be successful during accident conditions). Note that there is no reference to a time limit since these actions must be completed promptly. The paragraph starting on line 5 of page 29 was not intended to be in NEI 99-02, Rev. 0. All references to time constraints were intended to be removed from that document. Due to an oversight, the words were not removed. This will be corrected in the next revision of the document. **Alternate Response (NEI 8/29)** No, provided the configuration can be promptly restored in the control room without the loss of safety function. Restoration actions for the malfunction must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions) and must not require corrective maintenance or a significant problem diagnosis.		

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FAQ Log 9

Temp. No.	PI	Question/Response	Status	Plant/ Co.
9.5	IE02	**Proposed Replacement for FAQ 196 (Revisions to 196 indicated)** **Question** During a startup following a refueling outage (reactor at 24% power w/minimal decay heat), one feed water regulating valve failed open causing a loss of feed water control. In response, one of the two feed water pumps was manually tripped to minimize overfeeding of the steam generators. SG levels continued to rise, so the reactor was manually scrammed. Within one minute of scram, with normal heat removal still available through both main feedwater bypasses, the failed open feed water regulating valve was isolated by closing it's feed water block valve as part of Standard Post Trip Actions. Operators quickly diagnosed this as an uncomplicated reactor trip and completed the remaining steps of Standard Post Trip Actions. Eleven minutes after the scram with steam generator levels continuing to slowly rise, the remaining feed water pump was stopped to terminate overfeeding of the steam generators and avoid excess RCS cooldown. Nineteen minutes after the scram, the Reactor Trip Recovery procedure was entered. Thirty nine minutes after the scram, with steam generator levels down to normal levels, AFW was established at 81 gpm for normal startup feed water alignment. Three minutes later, the Plant Startup procedure was initiated. Mitigating systems such as Aux feed and Atmospheric Dump valves were not required nor used to establish scram recovery conditions. Rather, steam generator inventory provided by normal feed water and the normal steam path to main condenser via the normal steam bypass control system accounted for 100% capability for post scram RCS heat removal (i.e., no loss of capability for performing the heat removal function). Would this event count as a scram with loss of normal heat removal? **Response** No. The indicator counts events in which the normal heat removal path through the main condenser is not available and is not easily recoverable from the control room without the need for diagnosis or repair. In this event, the main feedwater system could have easily been returned to service at any time if needed.	Discussed 6/14/00 On-hold, NRC review ongoing. 7/12/00 – Response revised and approved. 8/2 NRC proposed revision to Response 9/20 – Approved Post 10/1.	SCE

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FAQ LOG 10				
Temp No.	PI	Question/Response	Status	Plant/ Co.
10.4	MS01 MS02 MS03 MS04	Question: ~~Is it necessary to perform a risk assessment to show that an overhaul maintenance activity is of low risk in order to exclude the hours in the unavailability indicator?~~ Response: ~~Yes. 10 CFR 50.65a(4) requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. The rule will be effective on November 28, 2000. Guidance on actions necessary to comply with the rule are contained in NUMARC 93-01, Revision 2. Section 11, as revised February 22, 2000, of this document provides guidance for the development of an approach to assess and manage the risk impact expected to result from the performance of maintenance activities. In the interim to qualify for the exclusion of unavailable hours from the unavailability indicator, licensees must perform that assessment and demonstrate that the planned configuration meets the requirements for normal work controls, as identified in Section 11.3.7.2 of NUMARC 93-01. Otherwise the unavailability hours must be counted.~~	Discussed 6/14/00 On hold, NEI review ongoing. Response revised, 7/11/00 (NRC) 7-12-00 On hold, NRC and NEI actions to confirm consistency with MR revision and associated guidance. Intent to finalize at next meeting. 8/4/00 – Discussed Under review. 9/21 – Discussed. Withdrawn.	NRC
10.5	MS01 MS02 MS03 MS04	Question: Is it appropriate to use the default value, that is, the period hours, for the hours that each EDG train is required to be operable when not all trains are required to be operable during shutdown? This results in a non-conservative performance indicator. Response: No. The default values in the guidance were provided as an option for licensees to use to reduce the data collection burden. In some cases, the default value is conservative. In other cases, such as with the EDGs, it may be non-conservative. The default values may be used when they are conservative. The non-conservative default values may not be used and the actual hours the train is required to be operable must be determined.	Discussed 6/14/00 On hold, NEI and NRC review ongoing	NRC
10.7	OR01		Discussed 6/14/00 On hold, NEI review ongoing Discussed 7/12/00 NRC/NEI action to propose/review alternate question/response 8/3/00 Replacement FAQs being developed. See 12.3 9/21 Withdrawn	NRC

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FAQ LOG 11				
Temp No.	PI	Question/Response	Status	Plant/ Co.
11.3	MS03	**Question:** Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question. **PART A** CR-3 has two EF System pumps and associated piping systems that are credited for Design Basis Accidents of Loss of Main Feedwater, Main Feedwater Line Break, Main Steam Line Break, and Small Break LOCA. A design criterion for the EF System is that a maximum time limit of 60 seconds from initiation signal to full flow shall not be exceeded for automatic initiation. Pumps EFP-2 (steam turbine driven) and EFP-3 (independent diesel driven) are auto-start pumps and are tested for the 60-second time criteria. EFP-3 was installed in 1999 to replace a third pump, the electric motor driven (EFP-1) pump, due to emergency diesel generator electrical loading concerns in certain accident scenarios. Per FSAR Section 10.5.2, "MAR [modification approval record] 98-03-01-02 installed a diesel driven Emergency Feedwater Pump (EFP-3) to functionally replace the motor driven Emergency Feedwater Pump (EFP-1) as the "A" EF Train." The motor driven pump does not receive an automatic start signal. The motor driven pump is interlocked with the diesel driven pump so that if the diesel driven pump is operating, EFP-1 will be tripped or its start inhibited. The motor driven pump is maintained for defense-in-depth. EFP-1 can be used to transfer water from the condenser hotwell into the steam generators during a seismic event, if long term cooling is necessary. EFP-1 can be used as a backup to EFP-2 to supply EFW to the steam generators for fires in the Main Control Room, Cable Spreading Room, and Control Complex HVAC Room. CR-3 is reporting RROP safety system unavailability performance indicator data on the basis of two EF pumps and trains. CR-3 is not reporting on EFP-1. CR-3 design and usage of EFP-1 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0. EFP-1 is safety-related and tested. However, EFP-1 is not required to be OPERABLE in any MODE in accordance with the Improved Technical Specifications (ITS). EFP-1 cannot replace EFP-3 to meet two train EFW ITS requirements. EFP-1 is included in the PRA but is not a "risk significant" component. EFP-1 is credited in the FSAR as noted above for providing defense-in depth and maintained for potential use in certain seismic and Appendix R conditions. Should this be reported as a third train of AFW?	Discussed with NRC, CR3 during 8/28 conf. call. 9/21 Discussed. Response added. Approved. Post 9/21.	Crystal River
		Response: No, since the pump has no operability requirements in the Technical Specifications.		

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FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.4	MS03	**Question:** Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question. **PART B** CR-3 has an independent motor driven pump and independent piping system for the Auxiliary Feedwater (AFW) System that is separate from the EF System. The AFW pump (FWP-7) and associated components are designed to provide an additional non-safety grade source of secondary cooling water to the steam generators should a loss of all main and EF occur. This reduces reliance on the High Pressure Injection/Power Operated Relief Valve (HPI/PORV) mode of long term cooling. This AFW source was added to CR-3 in 1988 in response to NRC concerns on the issue of EF reliability (Generic Issue 124). Per the FSAR, "The AFW source is non-safety grade and is not Class 1E powered or electrically connected to the emergency diesel generators. As such, it is not relied upon during design basis events and is intended for use on an "as available" basis only. AFW performs no safety function and there is no impact on nuclear safety if it fails to operate.....It is not environmentally qualified nor Appendix R protected.....Although the AFW source is non-safety grade it is credited by the NRC as a compensating feature in enhancing the reliability of secondary decay heat removal. Auxiliary feedwater may be used, as defense-in depth, during emergency situation when steam generator pressure has been reduced to the point where EFP-2 is no longer available or to avoid EFP-2 cyclic operation." FWP-7 is powered by an independent, non-safety related, diesel. FWP-7 is a manually started pump and the associated control valves are manually controlled from the Main Control Room. ~~FWP-7 is not safety related.~~ FWP-7 is not required by ITS to be OPERABLE in any MODE. FWP-7 cannot replace either EFP-2 or EFP-3 to meet two train EFW ITS requirements. CR-3 design and usage of FWP-7 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0. FWP-7 is credited in the FSAR for providing defense-in depth and as an additional source non-safety grade source of secondary cooling water to steam generators. Should this be reported as a third train of AFW? **Response:** No, since the pump has no operability requirements in the Technical Specifications.	Discussed with NRC, CR3 during 8/28 conf. call. 9/21 Discussed. Response added. Approved. Post 9/21.	Crystal River
11.5	MS01 MS02 MS03 MS04	**Question:** ~~FAQ 178 states that the exemption of planned unavailable hours due to overhaul maintenance can be applied "once per train per operating cycle". Does the limitation of "once per train per operating cycle" extend to support systems for a monitored system? In other words, if planned unavailable hours for a monitored system result from both planned overhaul maintenance of the monitored system and planned overhaul maintenance of a system that supports the monitored system; can both sets of hours be excluded (provided all other exclusion criteria are met)?~~ **Response:** ~~For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exclusion.~~	7/12/00 – Discussed. NEI action to propose response. 8/3/00 – NEI proposed response. 9/21 – Withdrawn	NEI

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FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.6	Gen	**Question:** FAQ 170 discusses correcting past unavailability hours for Emergency AC System surveillance testing which were found to be incorrectly reported to WANO. The FAQ response states that historical data does not have to be revised, except to ensure that the data is accurate back to the first quarter of 2000. Can this response be applied to any correction of performance indicator data that occurred in the historical (prior to first quarter of 2000) data time period? **Response:** Data in the historical submittal (through the end of 1999) does not require correction. However, data may be revised by the licensee if desired and as described and allowed by NEI 99-02.	7/12/00 – Discussed. On hold for review. 8/29 NEI response revision 9/21 Approved Post 10/1	
11.7	MS02	**Question:** In NEI 99-02, under the Support System Unavailability header, it is identified that in some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling *need not be reported* if cooling water from another source can be substituted. The rules further state that if both the monitored and support system pumps are powered by a class 1E electric power source, then a pump powered by a non- class 1E source may be substituted provided the redundancy requirements to accommodate single failure requirements for electric power and cooling water are met. At our site, the HPCS pump room is cooled by a safety related unit cooler, HVR-UC5. This unit cooler has non-safety related/non-Class 1E powered Normal Service Water (NSW) supplied to it and a safety related/Class 1E Standby Service Water (SSW) supplied to it as a backup cooling source. The SSW system has four 50% capacity pumps, two per train. Both trains of SSW merge into a common header at the unit cooler. If we remove one train of SSW from service can NSW be credited as a substitute thus keeping HVR-UC5 and the HPCS pump available? **Response:** In this case, no substitution is required, since the HPCS system is still available. Removal of one 100% train of SSW from the unit cooler has no effect on the availability of HPCS since one 100% train of SSW is still available to service the HVR-UC5 unit cooler. The single failure criteria should only be applied to cases where there is substitution of the support system and in cases where the mitigating systems have installed spares or redundant trains.	7/12/00 Discussed. On hold for review. 8/29 NEI removed plant name from response. 9/21 – Tentative Approval	River Bend
11.8	MS01 MS02 MS03 MS04	**Question:** Our Standby Service Water System (SSW) is designated as a Support System for each of the four mitigating systems. The system has two trains and each train has two 50% capacity pumps. At the mitigating system interface, the SSW support system either has both trains of SSW supplied to the cooling load or one SSW train exclusively supplying the cooling load. A train with one pump in service will supply the required SSW loads except the RHR train. The RHR train is normally valved out of service and is manually lined up to support a design basis accident condition some time after the automatic initiation sequence is completed. We consider all mitigating systems within a train, except RHR in that train, available with one SSW pump out of service. However, RHR, with the SSW from the other train available, is considered available. Have we calculated the availability correctly? **Response:** Yes. The mitigating systems that can be supplied by a single SSW train with one SSW pump in service are available.	7/12/00 Discussed. On hold for review. 9/21 – Tentative Approval	River Bend

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FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.9	MS02	**Question:** On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as "The ability of the monitored system to take suction from the condensate storage tank or [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel." However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from -the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI? **Response:** Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of the suction path from the suppression pool. (Editorial Note: The guidance in NEI 99-02 will be changed to eliminate the words "from the condensatge storage tank or," leaving only "from the suppression pool.".)	7/12/00 Discussed. On hold for review. 8/2/00 NRC – Proposed response revised. 9/19 NEI, response revised to reflect "Editor's Note" 9/21 – Tentative Approval	NRC
11.10	BI01	**Question:** Proposed replacement for FAQ 193 (Revisions to 193 indicated) The definition of the RCS Specific Activity PI is the maximum RCS activity as a percentage of the technical specification limit. Should licensees with limits more restrictive than the technical specifications use the more restrictive limit or the TS limit? **Response:** Licensees should use the most restrictive regulatory limit~~whether it is in technical specifications or a license condition~~ (e.g., technical specifications[TS] or license condition). However, if the most restrictive regulatory limit is insufficient to assure plant safety, then NRC Administrative Letter 98-10 applies, which states that imposition of administrative controls is an acceptable short-term corrective action. When an administrative control is in place as a temporary measure to ensure that TS limits are met and to ensure public health and safety, that administrative limit should be used for this PI.	7/12/00 Discussed. On hold for review. 8/2/00 – NRC revision to proposed response. 9/21 – Tentative Approval	NRC
11.11	IE03	**Question:** Regarding the Unplanned power change PI, I have the following questions: 1. Is the 20% full power intended to be 20% of 100% power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97)= 19%] 2. If an unplanned transient occurs which is greater than 20%, the operators stabilize the plant briefly and then cause a transient greater than 20% in the opposite direction, does that count as 2 hits against the PI? 3. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate? **Response:** 1. It is intended to be 20% of 100%. 2. In general, yes, however the specific scenario needs to be evaluated. 3. Licensees should use the power indication that is used to control the plant at the time of the transient.	7/12/00 Discussed. On hold for review. 8/2/00 NRC revision to question and response. 8/29 NEI response revision. 9/21 – Tentative Approval	NRC

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FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.12	IE03	**Question:** The licensee reduced power on both units to support grid stability in response to a fault on off-site transmission line 15616. Each of the licensee's two operating units are supplied from two 345 kilovolt (kV) lines. Line 15616, which supplies Unit 1 ~~from a Lake~~, was lost as a result of a static line failure. The power reduction was requested by the system load dispatcher in accordance with System Planning Operating Guide (SPOG) 1-3-F-1, "Station Operating Guidelines," Revision 1, to allow disabling the Unit 1 turbine generator trip scheme while line 15616 was out of service. With line 15616 out of service, a fault on the second line supplying Unit 1 (line 15501 from) would cause a Unit 1 turbine trip. The turbine trip would then cause a reactor trip (if reactor power is greater than the P-8 interlock setpoint of 32.1%). The turbine trip is intended to prevent overloading remaining grid circuits, causing the grid to become unstable. It is not a Reactor Protection System function. Reducing power and disabling the Unit 1 turbine trip scheme would prevent Unit 1 from tripping if line 15501 was faulted or lost. There were no on-site problems associated with the loss of the transmission line. The first paragraph of SPOG 1-3-F-1 states that "it is not necessary to take any corrective measures for stability for the outage of any single line provided that the protection system is normal. However, it may be desirable to disable the unit trip scheme(s) during single line outages." The power reductions requested by the load dispatcher (just over 20%) met the procedurally recommended output limitations for the station with line 15616 out of service with the stability trip scheme disabled. Does this situation count? **Response:** No. In the situation described, the power reduction would not count. The exception from counting unplanned power changes when directed by the load dispatcher is intended to exclude power changes directed by the load dispatcher under normal operating conditions due to load demand and economic reasons, and for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit. However, power reductions due to equipment failures that are under the control of the nuclear unit are included in this indicator.	7/12/00 Discussed. Action, NRC to rewrite question and response for clarification. 8/2/00 NRC rewrite of question and response. 8/3/00 NEI Removal of plant name. 9/19 NEI, minor mod of question. 9/21 – Tentative Approval	NRC
11.14	EP03	**Question:** During a scheduled siren test, a siren (or sirens) fail or cannot be verified to have responded to the initial test. A subsequent test is done to troubleshoot the problem. 1) Should the troubleshooting test(s) be counted as siren test opportunities? 2) Should failures during troubleshooting be considered failures? 3) Should post maintenance testing or system retests after maintenance be counted as opportunities? 4) If subsequent testing shows the siren to be operable (verified by telemetry or simultaneous local verification) without any corrective action having been performed, can the initial test be considered a success?	7/12/00 – On hold, NRC review/revision 8/29 NEI proposed response revision. 8/30 Question replaced with rewrite from 8/17 NRC/NEI meeting 9/21 – Tentative Approval	NRC

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FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: 1) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures. 2) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures. 3) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures. 4) Yes, but only if it is reasonably verified that the failure was in the testing equipment and not the siren control equipment, i.e., the siren would have sounded when called upon, even though the testing equipment would not have indicated the sounding. In the process of verifying that the failure is only with testing equipment, problems such as radio signal transmission weakness or intermittent signal interference should be eliminated as the cause. Maintenance records should be complete enough to support such determinations and validation during NRC inspection.		
11.15	PP01	Question: If perimeter intrusion equipment, CCTV monitoring equipment or systems supporting their functionality are damaged or destroyed by environmental conditions and remains unable to perform their intended function after the condition subsides (e.g., a lightning strike, wind, ice, flood) do you need to count any hours towards the performance indicator?	7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. 9/21 – Tentative Approval	\ComEd
		Response: No. ~~Compensatory hours are not counted for environmental conditions beyond the design of the equipment.~~If after the environmental condition clears, the zone remains unavailable, despite reasonable recovery efforts, the hours do not have to be counted.		
11.16	PP01	CLARIFICATION NEEDED ON "FAQ" # ID-59 ISSUED WITH NEI 99-02 REV. 0 MARCH 28 2000 -- "COMP. POSTING FOR NON-FAILURE OF EQUIPMENT" In FAQ 59 and resulting response it states in part that, if an IDS system segment needs to be declared inoperable due to a Security Plan commitment of "x" number of false alarms received, the zone would need to be comped, repair / test the segment, return to operable and remove the comp post. In the response it goes on to state that if there is no equipment malfunction and the system would still have alarmed during intrusion (still capable of performing its intended function) then the man hours that were established as part of the "precautionary maintenance" activity would not be counted. Question: If the zone / segment remains operable (still capable of performing its intended function) but is "declared" inoperable due to a Security Plan commitment of "x" number of false alarms received is it necessary to have maintenance "check" the zone / segment prior to declaring the zone operable? Or, can functional testing be conducted by security on that zone / segment assuring that it was capable of alarming during an intrusion?	7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. 8/29 NEI response revision. 9/21 – Discussed. On hold.	ComEd

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FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: If in the scenario identified above, a zone/segment tests "OK" as performing its intended function (per the normal test procedures for zone operability) there would be no need to have maintenance perform any actions prior to declaring the zone operable. Therefore, the hours associated with this situation would not be counted.		
11.18	MS01	**Question:** The station UFSAR states that operator actions are required to restore the EDG room ventilation system following: 1) a fire protection system actuation 2) a HELB occurring outside of the EDG rooms. The restoration actions (manually open several sets of dampers) are directed by an operating procedure. During certain fire protection system surveillances, the EDG room ventilation system dampers are closed to the same configuration as when a HELB or fire protection system actuation occurs. No other actions are taken that would otherwise affect EDG start and load capability. The steps necessary to return the ventilation subsystem to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individual specifically involved with restoring the ventilation is briefed on the time restraints and dedicated to the testing. Since the UFSAR credits the operator actions required to restore the system to its normal operating configuration following a fire protection actuation or HELB, the actions taken to restore ventilation during testing would be similar to those credited in the UFSAR. Can the EDG be considered available during the period the room vent fan is unavailable due to the fire protection surveillances?	8/17/00 – Licensee proposed response added. 9/21 – Approved as revised. Post 10/1	Braidwood /ComEd
		~~Licensee Proposed~~ **Response:** No. The situation described is more complex than the few simple operator actions that current guidance allows to be excluded. Note: This response is consistent with FAQ 150 and should be applied to data covering 2Q2000 and forward. ~~The EDG should be considered available and Fault Exposure Hours should not be reported for this event because the EDG never enters a condition where system or subsystems necessary for operability (as determined by formal engineering analysis) are unavailable during the surveillance. This will maintain a consistent approach in comparison with the industry WANO indicator reporting.~~ ~~The EDG automatic start and load features are still available during all phases of the testing. The EDG would start and load on an accident signal in accordance with its design. The room cooling subsystem could be returned to service prior to the room temperature reaching the previously analyzed limit and precautions in the procedure specify the previously analyzed time limit for restoration. The steps necessary to return the ventilation subsystem to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individuals specifically involved with returning the room cooler subsystem to available are briefed, aware of their responsibility and dedicated to the testing. The actions required to restore ventilation are consistent with the system design basis assumptions in the UFSAR and are acceptable.~~		

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FAQ LOG 12				
Temp No.	PI	Question/Response	Status	Plant/ Co.
12.1	MS01 MS02 MS03 MS04	Proposed Replacement for FAQ 178 (Revisions to 178 indicated) FAQ on Planned Overhaul Hours The concept of not counting major on-line overhaul hours against the SSU performance indicator is sound. It allays a prevalent concern that a licensee could end up with a white indicator, and potentially a degraded cornerstone, primarily due to performing on-line maintenance that is considered in PSA analyses and bounded by the Tech. Spec. AOT, and has been determined to be a good business practice [to reduce outage length, etc.]. To ensure consistency of reporting and inspector oversight, the following issues should be addressed: 1. What defines overhaul versus non-overhaul maintenance? ~~2. What is considered to be a major component for overhaul purposes?~~ ~~2.~~3. Is application of planned overhaul hours limited to systems for which a risk informed AOT extension has been approved? ~~3.~~4. Is there a limit to the number of planned overhaul outages a licensee can report on a given system / train? ~~4.~~5. Can an overhaul be performed in two segments in separate AOTs during an operating cycle? ~~5.~~6. If an overhaul maintenance interval is scheduled to take 120 hours, but the actual unavailable interval is greater [say 140 hours] but still bounded by T.S. AOT, can the entire interval be designated as planned overhaul hours, or is only the scheduled interval appropriate? ~~6.~~7. Can additional non-overhaul maintenance be performed during a planned overhaul maintenance interval? ~~7.~~8. Can Major rebuild tasks necessitated by an unexpected component failure be counted as overhaul maintenance? [Example: RHR pump wipes a motor bearing during surveillance run. It is decided to pull PM activities ahead to replace the motor with a spare.] ~~9.~~ Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of "once per train per operating cycle" extend to support systems for a monitored system?	NRC –Proposed replacement 8/28 9/21 – Discussed. Revisions to response. Approved. Post 10/1/00	NRC

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Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: NOTE: This answer applies to how unavailable hours are counted for PI purposes. It does not establish or recommend any changes in regulatory requirements or licensee maintenance actions. This FAQ is a clarification and applies to data submittals covering 4Q2000 data and beyond.~~of original intent. Data previously submitted (First Quarter 2000 data and forward) should be reviewed and revised if necessary.~~ 1. ~~Overhaul tasks are those that require disassembly of major components performed in accordance with an established preventive maintenance program~~Overhaul maintenance comprises those activities that are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability. Overhauls include disassembly of major components and may include replacement of parts as necessary, cleaning, adjustment, lubrication as necessary, and reassembly. 2. A major component is a prime mover – a diesel engine or, for fluid systems, the pump or its motor or turbine driver or heat exchangers. ~~2.~~3. ~~No, application is for any AOT sufficient to accommodate the overhaul hours~~ No. Any AOT sufficient to accommodate the overhaul hours may be considered. However, to qualify for the exemption of unavailable hours, licensees must have in place a quantitative risk assessment. This assessment must demonstrate that the planned configuration meets either the requirements for a risk-informed TS change described in Regulatory Guide 1.177, or the requirements for normal work controls described in NUMARC 93-01, Section 11.3.7.2. In addition, all other requirements described in the response to this FAQ must be met. Otherwise the unavailable hours must be counted. The Safety System Unavailability indicator excludes maintenance-out-of-service hours on a train that is not required to be operable per technical specifications (TS). This normally occurs during reactor shutdowns. Online maintenance hours for systems that do not have installed spare trains would normally be included in the indicator. However, some licensees have been granted extensions of certain TS allowed outage times (AOTs) to perform online maintenance activities that have, in the past, been performed while shut down. Acceptance guidelines for such TS changes are given in Sections 2.2.4 and 2.2.5 of Regulatory Guide 1.174 and Section 2.4 of Regulatory Guide 1.177. These guidelines include demonstration that the change has only a small quantitative impact on plant risk (less than $5x10^{-7}$ incremental conditional core damage probability). It is appropriate and equitable, for licensees who have demonstrated that the increased risk to the plant is small, to exclude unavailable hours for those activities for which the extended AOTs were granted. However, in keeping with the NRC's increased emphasis on risk-informed regulation, it is *not* appropriate to exclude unavailable hours for licensees who have not demonstrated that the increase in risk is small. In addition, 10 CFR 50.65(a)(4), which goes into effect on November 28, 2000, requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. Guidance on a quantitative approach to assess the risk impact of maintenance activities is contained in the latest revision of Section 11.3.7.2 (dated February 22, 2000) of NUMARC 93-01, Revision 2. That section allows the use of normal work controls for plant configurations in which the incremental core damage probability is less than 10^{-6}. Licensees must demonstrate that their proposed action complies with either the requirements for a risk-informed TS change or the requirements for normal work controls described in NUMARC 93-01. ~~3.~~4. Yes. Once per train per operating cycle. ~~4.~~5. Yes, provided that no more than two segments be used and the total time to perform the overhaul does not exceed one AOT period. ~~5.~~6. If the unavailability is caused by activities designated as planned overhaul maintenance, the hours should not be counted in the unavailability indicator. If the additional unavailability is caused by a failure that would prevent the fulfillment of a safety function, the additional hours would be non-overhaul hours and/or potential fault exposure hours, and would count toward the indicator. (Also, see footnote 3 page 26 Rev 0.) ~~6.~~7. Yes, as long as the outage duration is bounded by overhaul activities, other activities may be performed. If the overhaul activities are complete, and the outage continues due to non-overhaul activities, the additional hours would be non-overhaul hours and would count toward the indicator. ~~7.~~8. No. 9. For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours.		
12.2	IE02	**Question:** Following a plant trip, operators closed the MSIVs due to a stuck open steam dump valve. RCS temperature was maintained using atmospheric dump valves. Does this count as a scram with loss of normal heat removal?	9/21 – Approved. Post 10/1	NRC

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Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: Yes. The MSIVs could not be recovered because of the stuck open steam dump valve.		
12.4	IE02	**Question:** In the Scrams With a Loss of Normal Heat Removal performance indicator, the definition of "loss of normal heat removal path" includes loss of main feedwater. Our plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps then are designed to start on low steam generator level (which is expected following operation above low power conditions), providing our normal heat removal. A clarifying note in the Guideline clearly states that "Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on a reactor scram, are not counted in this indicator." Also, the response to FAQ 65 states that "The PI is monitoring the use of alternate means of decay heat removal following a scram." If our plant receives a spurious or invalid feedwater isolation signal, our main feedwater ~~pumps will trip and a plant scram will occur. The auxiliary feedwater pumps will start on the loss of the main feedwater pumps,~~ prior to reaching a low SG level condition. In this example, main feedwater still isolates, although not in the normal fashion, auxiliary feedwater provides the normal heat removal, and no alternate means of decay heat removal is required. This is not believed to be a Scram with a Loss of Normal Heat Removal. Is this the correct interpretation? **Alternate Question (NRC Feedback form from Kewaunee)** During a typical plant trip, auxiliary feedwater auto-starts on low steam generator level, main feedwater isolation valves auto-close, and, per emergency procedures, the main feedwater pumps are stopped. Based on this sequence of events, the licensee considers auxiliary feedwater as the "normal heat removal path" and not main feedwater. Consequently, the licensee did not classify a plant trip caused by loss of all feedwater as a scram with loss of normal heat removal. Is this correct? ~~Licensee Proposed~~ **Response:** Yes. See FAQ 65 ~~Since the normal heat removal path was utilized and an alternate heat removal system was not required, this would not count toward the "Scram with Loss of Normal Heat Removal" performance indicator.~~ **Response to Alternate Question** No. Any reactor scram caused by the loss of all feedwater (or decreasing condenser vacuum) counts as a scram with loss of normal heat removal. For purposes of this PI, the normal heat removal path includes main feedwater, regardless of the plant design or response to a trip; auxiliary feedwater is <u>not</u> to be used as the normal path.	NRC Alternate question and response, 8/28 9/19 NEI Revision of "licensee proposed response" 9/21 – Discussed. On hold.	Kewaunee

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FAQ LOG 12

Temp No.	PI	Question/Response	Status	Plant/ Co.
12.5	EP01	**Question:** Currently the "Communicator" key ERO positions for event notification are defined as the ERO position responsible for the notifications, not just a telephone talker. If the key position person delegates completion of the notification form to another individual, but keeps responsibility for approval (must review and sign the form before offsite notifications are made), must the person completing the form be considered a Key ERO position also? It is understood that responsibility for approving the notification implies responsibility to verify the data recorded and to challenge inconsistencies before authorizing the notification. **Alternate Question (8/30 NRC)** NEI 99-02, Rev 0, page 100, lines 11-15, discusses the role of communicators (TSC and EOF), who provide offsite notifications. A site has identified the TSC and EOF senior managers as communicators for the purposes of the tracking drill participation. These individuals ultimately approve all offsite communications from their respective facilities, however, they do not collect data for the notification form. The licensee's basis is that NEI 99-02 addresses the desire to not track "phone talkers". 1) Is this an appropriate interpretation of 99-02?	8/30 NRC alternate question and response provided and discussed. 9/21 – On hold	Kewaunee
		Licensee Proposed Response: In the example provided, the person completing the form does NOT have to be considered a Key ERO position. **Response to Alternate Question** 1) No. The expectation of 99-02 is that the participation of the communicators responsible for collection of timely and accurate data for the notification form will be tracked. However, there are cases where the position responsible for approval (the senior managers in the above example) actually collects the data for the form, approves it and hands it off to a phone talker. Where this is the case, the senior manager is also the communicator and the phone talker need not be tracked.		

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FAQ LOG 12

Temp No.	PI	Question/Response	Status	Plant/ Co.
12.6	IE03	**Question:** **Question rewritten by Pallisades (see 8/4/00 log for prior version)** This FAQ raises a question regarding the proper interpretation of the wording of this PI. NEI 99-02 states the purpose of this PI as: "This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions." Our plant planned a sequence of power changes and equipment manipulations to deal with a secondary chemistry problem. The plan was ready >72 hours in advance, and a written schedule existed. During execution of the plan, an additional equipment problem was discovered, but plant management chose to continue with the planned sequence of power changes, and to address the emergent equipment issue later in the planned outage. Had it occurred by itself, the equipment problem may have required a power change in excess of 20%. However, the problem did not cause ~~significant~~ departure from the already planned and scheduled activities, and did not cause urgent response from Operations staff to mitigate the equipment problem. There were no reactor safety implications. Consistent with the intent of the PI, we believe this event should not be counted against this PI. However, ~~part of the PI definition on page 18 of NEI 99-02~~ states that "Unplanned changes in reactor power ~~are changes in reactor power~~ that are initiated in less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater than 20% full power to resolve." This wording could be viewed in two ways: This was a newly emergent off-normal condition that, by procedure, would have "required" the plant to reduce power if the condition were not fixed, it should be counted whether or not the power reduction was already planned and scheduled. Or The emergent condition was not what initially caused the planned reduction in power, but was simply a secondary reason to proceed with the existing plan, the condition did not "result in" a change in power level greater than 20%. Should the sequence of power changes be counted as an unplanned power change? **Response:** No. This sequence of power changes would not count. ~~Minor modifications to a planned power change protocol in response to events are not considered unplanned power changes and are not counted toward the performance indicator.~~	8/4/00- Discussed. Pallisades to prepare shortened version of FAQ for consideration. 8/15/00 – Question rewritten by Pallisades. Proposed response added by NEI. 9/21 Revised. Tentative Approval.	Pallisades
12.7	IE03	**Withdrawn**	8/29 NEI action to obtain clarification from Columbia. 8/31 Withdrawn by Columbia	Columbia

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FAQ Log 13				
Temp No.	PI	Question/Response	Status	Plant/ Co.
13.1	IE03	**Question:** You have a slow leak on a feedwater pump and a work request is initiated and placed on the 12 week schedule, then after 72 hours passes the leakage increases, but the work package is still applicable. You immediately decrease power to fix the pump. Is this considered an unplanned power change since you had a work package written and there was greater than 72 hours? **Response:** The event would count as an Unplanned Power Change. Power changes caused by or in response to off-normal events during the course of a pre-planned activity, count as unplanned power changes when a determination is made that the off-normal events necessitated a course of action that was outside contingency planning in place for the pre-planned activities. In these instances, the off-normal events cause, in effect, an exiting of the preplanned course of action and any power changes that occur following the exit of the plan are counted toward the performance indicator. Minor modifications to a planned activity in response to events are not considered unplanned power changes and are not counted toward the performance indicator.		Beaver Valley
13.2	IE023	**Question:** Crystal River Unit 3 (CR-3) is configured with two once-through steam generators (OTSGs). Two Main Steam Isolation Valves (MSIVs) are installed in each of the two main steam lines. On August 27, 1998, CR-3 was in MODE 1 operating at 100 percent RATED THERMAL POWER. While troubleshooting a half trip signal on the Emergency Feedwater Initiation and Control (EFIC) System Channel A Main Steam Line Isolation (MSLI), both MSIVs to OTSG A closed. This action isolated steam relief to the condenser through the turbine bypass valves from the A OTSG and isolated the steam supply to Main Feedwater Pump (MFP) A. As required by administrative procedures, the reactor operator initiated a manual trip upon closure of the MSIVs. After the manual trip, the OTSG A level lowered enough to initiate Emergency Feedwater (EFW). EFW controlled level in both OTSGs as designed, although MFP B remained in service and available at all times. OTSG B provided RCS heat removal to the condenser with EFW maintaining OTSG level. Does this count? **Response:**		Crystal River 3
13.3	EP03	**Question:** Siren systems may be designed with equipment redundancy or feedback capability. It may be possible for sirens to be activated from multiple control stations. Feedback systems may indicate siren activation status, allowing additional activation efforts for some sirens. 1) A siren system has two normally attended control stations from which the system may be activated. If a siren test from one station is unsuccessful can a test performed from the second station be considered as a part of the regularly scheduled test? 2) A siren test technician sent multiple activation signals to a siren that initially appeared not to respond. The siren responded. Can the multiple signals be considered as the regularly scheduled test and hence a success?	8/30 – Discussed 9/15 – NRC, Revision of response 9/21 – Tentative Approval	NRC

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FAQ Log 13

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: 1) Yes, if the use of redundant control stations is in approved procedures and is part of the actual system activation process. A failure of both systems would only be considered one failure, where as the success of either system would be considered a success. If the redundant control station is not normally attended, requires set up or initialization, it may not be considered as part of the regularly scheduled test. Specifically, if the station is only made ready for the purpose of siren tests it should not be considered as part of the regularly scheduled test. 2) Yes, if the use of multiple signals is in approved procedures and part of the actual system activation process. However, the use of multiple activation signals to achieve successful siren tests may not include any activities outside the regularly scheduled test, such as troubleshooting, post maintenance testing or activation signals sent after the initial activation process has ended.		
13.4	EP	Question: A licensee used same scenario for each of the three response teams. The drills contributed to DEP and ERO statistics. Repetitive use of the scenario has the potential to skew the PI success rate if scenario confidentiality is not maintained. There was no indication that drill participants were intentionally informing other teams about the scenario, but discussions of the drill could inadvertently reveal facts about the scenario. ~~1)~~ Is it permissible to repeat the use of scenarios in drills that contribute to DEP and/or ERO statistics? ~~2) What is the NRC expectation with regard to scenario confidentiality?~~	8/30/00 – Discussed 9/15 – NRC response revision 9/21 – Revised. Tentative Approval	NRC

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FAQ Log 13

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: ~~1) Yes, if a reasonable level of scenario confidentiality is maintained.~~ ~~2) NRC does not expect the licensee to develop new scenarios for each drill or each team. However, it is expected that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a proficiency-enhancing evolution. There are many processes for the maintenance of scenario confidentiality that are generally successful. These include confidentiality statements on the signed attendance sheets, spoken admonitions by drill controllers and the like. A reasonable level of confidentiality means that some scenario information could be inadvertently revealed and the drill still be a valid proficiency enhancing evolution. However, it is expected that the licensee will remove from the statistics drill opportunities that were not valid due to scenario compromise and address the reasons for such a compromise.~~ Yes, the licensee need not develop new scenarios for each drill or each team. However, it is expected that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a proficiency-enhancing evolution. A reasonable level of confidentiality means that some scenario information could be inadvertently revealed and the drill remains a valid proficiency-enhancing evolution. It is expected that the licensee will remove from the drill performance statistics any opportunities considered to be compromised. There are many processes for the maintenance of scenario confidentiality that are generally successful. Examples may include the following: • Confidentiality statements on the signed attendance sheets, • Spoken admonitions by drill controllers. Examples of practices that may challenge scenario confidentiality include: • Drill controllers or evaluators or mentors, who have scenario knowledge becoming participants in subsequent uses of the same scenarios, • Use of scenario reviewers as participants.		

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FAQ Log 14				
Temp No.	PI	Question/Response	Status	Plant/ Co.
14.1	MS01 MS02 MS03 MS04	**Proposed Replacement for FAQ 190 (FAQ 190 and current response shown in BOLD, followed by proposed replacement)** **(FAQ 190)In reference to Page 29, in NEI 99-02 Revision 0, "Removing (Resetting) Fault Exposure Hours": Clarification is needed for the third bullet which states, "Supplemental inspection activities by the NRC have been completed and any resulting open items have been closed out in an inspection report."** **What if the inspection in question covered and documented more activities than just those related to the fault exposure hours. Do the ancillary findings (those not related to the root cause or prevention of recurrence to the fault exposure finding(s)) need to be closed out or just the findings related to the condition causing the fault exposure hours?** **Also, it is possible that the fault exposure hours would not place the indicator in the white band and that no supplemental inspection activities would be required.** **Response** **1. The wording. "any resulting open items" means any items related to the condition causing the fault exposure.** **2. If there is no supplemental inspection, there are no open items to be closed out. Consequently, this would not be a criterion for removal of fault exposure hours in this case.** **Question (Proposed Replacement for FAQ 190):** The guidance in NEI 99-02 states that fault exposure hours may be removed after certain criteria are met. One criterion is that supplemental inspection activities by the NRC have been completed and all open items have been closed out. If a licensee has fault exposure hours that meet all other stated criteria (336 hours, corrective actions completed, and four quarters have elapsed) but the indicator is still green, does the baseline inspection count in place of the supplemental inspection? Also, please clarify the intent of the phrase "after 4 quarters have elapsed from discovery." Response: 1. No. Fault exposure hours may be removed only if the indicator is outside the green band so that supplemental inspection is necessary (and all other stated criteria are met). The intent of this provision was to allow the removal a large number of fault exposure hours due to a single event or condition so that a licensee would not be outside the green band for an extended time period. There are two reasons for this: (1) after the stated criteria are met, the PI is no longer considered to be indicative of current performance; and (2) unavailable hours accumulated later would put the licensee further into the white band but would not trigger any further NRC action, since the white band is 1.5 to 2 times as wide as the green band. For these reasons, the hours may be removed to reset the indicator so that further fault exposure hours could trigger further NRC response. 2. The intent of the phrase "after 4 quarters have elapsed from discovery" was that the indicator would be non-green for 4 quarters minimum, regardless of when the corrective actions were completed and the supplemental inspection closed out. The quarter in which the fault exposure hours is identified would be the first non-white quarter, and 12 months (four quarters) later, assuming all required conditions are met, the hours could be removed from the calculation for that quarter.		NRC feedback form from Catawba
14.2	MS05	Question: Are failures of the RCIC system included in the Safety System Functional Failure indicator only if RCIC is reportable in accordance with 10 CFR 50.73(a)(2)(v)?		NRC

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Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: No. Because RCIC has safety significance at BWRs, and because the ROP is a risk-informed process, failures of RCIC that are reported are included in the SSFF. While the intention of NEI 99-02 was to report only failures meeting the reporting criteria of 10 CFR 50.73(a)(2(v), RCIC reporting has been inconsistent among licensees. To provide consistency in reporting and in the ROP, all failures of RCIC should be reported. The question of RCIC reportability per 10 CFR 50.73 is currently under review by the NRC.		
14.3	IE02	**Proposed Replacement for FAQ 142 (Revisions to 142 indicated)** **Question:** Under the Scram with Loss of Normal Heat Removal performance indicator in NEI 99-02 Draft D, the Definition of Terms states that a loss of normal heat removal path has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of main steam isolation valves or loss of turbine bypass capability. The purpose of the indicator is to count scrams that require the use of mitigating systems, however, instances that meet the above criteria in a literal sense could occur without the necessity of using mitigating systems. For example, a short term loss of main feedwater injection capability due to pump trip on high reactor water level post-scram is a common BWR event. Under these conditions, there is ample time to restart the main feed pumps before addition of water to the vessel via HPCI or RCIC is required. A second example would be a case where the turbine bypass valves (also commonly called steam dump valves) themselves are unavailable, but sufficient steam flow path to the main condenser exists via alternate paths (such as steam line drains, feed pump turbine exhausts, etc.) such that no mitigating systems are called upon. **Response:** ~~If an alternate heat removal system is put into use, it counts toward the performance indicator~~ The determining factor in this indicator is whether or not the normal heat removal path is *available* to the operators, not whether the operators choose to use that or some other path. The indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable from the control room without the need for diagnosis or repair. There was no intent to provide incentive for operators to operate the plant in a manner contrary to best practices for a given situation.		NRC
14.4		**Proposed replacement for FAQ 151 (Revisions to 151 indicated)** **Question:** Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, Hours Train Required states the Emergency AC power system value is estimated by the number of hours in the reporting period because emergency generators are normally expected to be available for service during both plant operations and shutdown. Considering only one train of Emergency AC power systems may be required in certain operational modes (e.g. when defueled), should actual required hours be determine for each train in place of using the default period hours? In certain operational modes it appears inconsistent to use period hours for hours required, yet not report the unavailable hours if a train is removed from service and Technical Specifications are still satisfied. **Response:** For the situation described above, it is acceptable to report the default value, or ~~that is~~ period hours, given the current NEI 99-02 guidance. This guidance is being evaluated to account for the above noted scenario, as it relates to a non-conservative SSU value being reported.		NRC

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FAQ Log 14

Temp No.	PI	Question/Response	Status	Plant/ Co.
14.5	MS01 MS02 MS03 MS04	**Question:** NEI 99-02 [page 26] allows for exclusion of test activities from Planned Unavailable Hours if "... the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." NEI 99-02 goes on to state that "The intent of this paragraph 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." During the performance of certain routine surveillance's, such as Slave Relay Testing, a control switch in the Control Room may be temporarily placed in an "out-of-normal" position to support the test. An example would be placing a Residual Heat Removal Pump switch in the "Pull-to-Lock" position. Can the time that this switch is in this position be excluded from Planned Unavailability Hours if the following conditions are met? 1) This switch is not danger tagged or otherwise restricted from being promptly returned to its normal position, and 2) this switch is within the control responsibilities of a regularly assigned control room operator(s), and 3) this switch can be virtually certain to be successfully restored to its proper position by initial steps taken per the station's Emergency Operating Procedures for immediate response to an accident condition. Does a control room operator have to be specifically designated as responsible for the restoration of a component in the control room, under the same conditions noted above, if such restoration can be virtually certain to be successful under the station's Emergency Operating Procedures for immediate response to an accident condition?		Seabrook
		Response: The answer to the first question is "Yes". Positioning a switch in the Control Room to support test/surveillance activities does not render the respective system or train "unavailable" if that switch position is either overridden by an actual emergency actuation signal or that switch can be returned to its normal position promptly by a control room operator without requiring additional actions such as clearing tags. If the position of this switch would be verified or returned to "normal" by procedures intended to guide the control room operators through a sequenced, directed response to an actual emergency, it can be considered to be virtually certain to be successfully restored. The answer to the second question is "No". A specifically designated (i.e., "dedicated") control room operator is not required to be assigned for component restoration if the component can be promptly returned to its normal condition by a control room operator without requiring additional actions such as clearing tags. The position of the component would be verified or returned to "normal" by procedures intended to guide the control room operators through a sequenced, directed response to an actual emergency.		
		Question: **Response:**		
		Question: **Response:**		
		Question: **Response:**		

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FAQ - EP 13.4 DRAFT DRAFT Input

EP 13.4

A licensee used same scenario for each of the three response teams. The drills contributed to DEP and ERO statistics. Repetitive use of the scenario has the potential to skew the PI success rate if scenario confidentiality is not maintained. There was no indication that drill participants were intentionally informing other teams about the scenario, but discussions of the drill could inadvertently reveal facts about the scenario.

Question:

Is it permissible to repeat the use of scenarios in drills that contribute to DEP and/or ERO statistics?

Answer:

Yes, the licensee need not develop new scenarios for each drill or each team. However, it is expected that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a proficiency-enhancing evolution. A reasonable level of confidentiality means that some scenario information could be inadvertently revealed and the drill remains a valid proficiency-enhancing evolution. It is expected the licensee will remove from the drill performance statistics any opportunities considered to be compromised.

There are many processes for the maintenance of scenario confidentiality that are generally successful. Examples may include the following:

- confidentiality statements on the signed attendance sheets,
- spoken admonitions by drill controllers.

Examples of practices that may challenge scenario confidentiality include:

- Drill controllers or evaluators or mentors, who have scenario knowledge becoming participants in subsequent uses of the same scenario,
- Use of scenario reviewers as participants.