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

MEMORANDUM TO: Michael R. Johnson, Section Chief
Inspection Program Branch
Division of Inspection Program Management

FROM: August Spector
Inspection Program Branch
Division of Inspection Program Management

August Spector

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON JUNE 14, 2000

On June 14, 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. Proposed Operator Re-qualification Human Performance SDP
4. Proposed Transportation SDP changes
5. Industry Perspective on Unplanned Power Change Indicator
6. NEI Proposal Performance Indicators Initiating Events Cornerstone
7. Operator Reactor Assessment Program Manual Chapter 0305 Draft
8. Performance Indicator Flow Chart
9. Frequently Asked Question Log 7, 8, 9
10. Additional Frequently Asked Questions

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|---|---|---|---|---|---|---|---|---|
| NAME: | AKSpector | | ALMadison | | | | | |
| DATE: | 7/26/00 | | 7/27/00 | | | | | |

**OFFICIAL RECORD COPY**

Agenda of Meeting
June 14, 2000

1. Discussion of Proposed Operator Re-qualification: Human Performance SDP
2. Discussion of Performance Indicators
3. Discussion of Transportation SDP -- Report by NEI
4. Discussion of Operating Reactor Assessment Program, Chapter 0305
5. Discussion of proposed Industry Perspective on Unplanned Power Change Indicators
6. Review and update of frequently asked questions Log 7, 8, and 9
7. Future meetings scheduled for July 12, 2000 and August 8, 2000

Attachment 1

List of Attendees on June 14, 2000

| NAME | AFFILIATION |
| --- | --- |
| August Spector | NRC |
| A. K. Krainik | APS |
| Dennis Hassler | PSEG |
| David Robinson | NPPD |
| James Chase | OPPD |
| John Butler | NEI |
| Serita Sanders | NRC |
| Kevin Borton | PEPCO Energy |
| Don Hickman | NRC |
| Bill Wallack | McGraw-Hill |
| Alan Madison | NRR |
| Tom Houghton | NEI |
| Stan Ketelsen | PG&E |
| Charles Willbanks | NUS |
| Mark Burzynski | TVA |
| Wade Warren | Southers Nuclear |
| Don Norkin | NRC |
| William Dean | NRC |
| Michael Johnson | NRC |
| Steven Unglesbee | NRC |
| Stephen Klementowicz | NRC |
| William Ward | NRC |
| Frank Talbot | NRC |
| Don Olson | VA Power |
| Randall Mika | COMED |
| Ed Wenzinger | NUSIS |

Attachment 2

**Proposed Operator Requalification**
**Human Performance**
**Significance Determination Process (SDP)**

JUNE 02, 2000

Background:

The attached flowchart and matrix comprise the proposed process for determining the risk significance of issues identified during an inspection of licensed operator requalification program or by a resident inspector's observation of requalification activities. This process covers only those issues related to operator requal. Performance errors made by a licensed operator leading to or during an actual operational event are an integral part of the overall outcome of the event and would be reflected in the outcome of the reactor significance determination process.

This SDP starts when an operator requal issue is identified. It can be related to the programmatic aspects (e.g. exam quality) or to the performance of licensed operators during the annual operating test. This SDP is applicable to all requal issues. Issues related to all licensed operators, including both shift and staff crews, with either active or inactive licenses, are covered by this process. The process is applicable to all license holders since a staff crew could, at any time, be asked to go on-shift and because an inactive license holder needs only to spend the required time on-shift to activate a license.

The SDP Flow Chart:

The parts of the the SDP process related to the written and JPM portions of requal (pages 1 and 2 of the flowchart), address exam quality and security and the performance of multiple individuals. The risk determination assumes that a single individual failure in requal does not rise to the risk significance of a green finding. However, when multiple failures are considered, 20% has been selected as the threshold for acceptable number of failures. This is generally consistent with the guidance in the examination standards of NUREG-1021, Rev. 8. Thus, more than 20% unacceptable written test items is the quality threshold; more than 20% of the operators failing the written portion is the performance threshold; more than 20% of the operators failing the job performance measures (JPMs) is the JPM performance threshold, etc.

The simulator portion of the SDP (pages 3 and 4 of the flowchart) evaluates scenario quality and security and performance of crews. Again, an individual failing in the simulator portion does not rise to the risk significance of a green finding. When crews fail simulator scenarios, it is impossible to determine exactly how long their performance may have been deficient. Therefore, in the absence of specific information, the assumption is that failed crews would have been unable to perform the failed action or activity since the last successful annual operating test. The risk significance of crew performance depends on the percentage of crews that have failed, whether they were remediated before returning to shift, and whether the facility has a green or higher failure rate (as determined by the SDP Simulator Operational Evaluation Matrix) in the previous annual operating test. The risk assessment of operator performance on

Attachment 3

(ADAMS ML 003713886 Accession# Package) For Attachment #3 the simulator should include all of crews tested even if the inspectors witnessed testing of only some of the crews.

The Simulator Operational Evaluation matrix has been added to the SDP to address multiple crew failures. The "Number of Crews that took the Annual Operating Test" includes multiple units in order to accommodate those instances where operators hold dual unit licenses. If a multiple unit site has separate unit licenses, the matrix should be used to assess the results at each of the units. Once again, to be compatible with NUREG-1021, Rev. 8, an UNSAT requal program is one in which more than 33% of the crews have failed, and is considered a white finding.

Several of the decision blocks on page 4 of the flow chart deserve further explanation.

- "Failure rate green on matrix?" If the failure rate is between 20% and 33% (<u>not</u> an UNSAT program), the concerns are whether or not the crew(s) was remediated before returning to shift and whether or not the failure rate was green or higher on the last annual operating test. Credit is earned for remediation along with a successful annual operating test from last year, while escalation occurs when crews are remediated, but were green or higher on the previous annual operating test. The latter being a potential indication of ineffective corrective actions associated with the failures the previous year.

- "NF on matrix?" This accounts for remediation and last year's annual operating test results when a <20% failure rate (i.e. no finding) occurs. If there was no remediation or there was remediation but last year's performance was poor, the 'no finding' is escalated to a 'green finding.' Otherwise it remains 'no finding.' Any other color in the matrix remains that color; no need for further analysis.

# Simulator Operational Evaluation

June 02, 2000

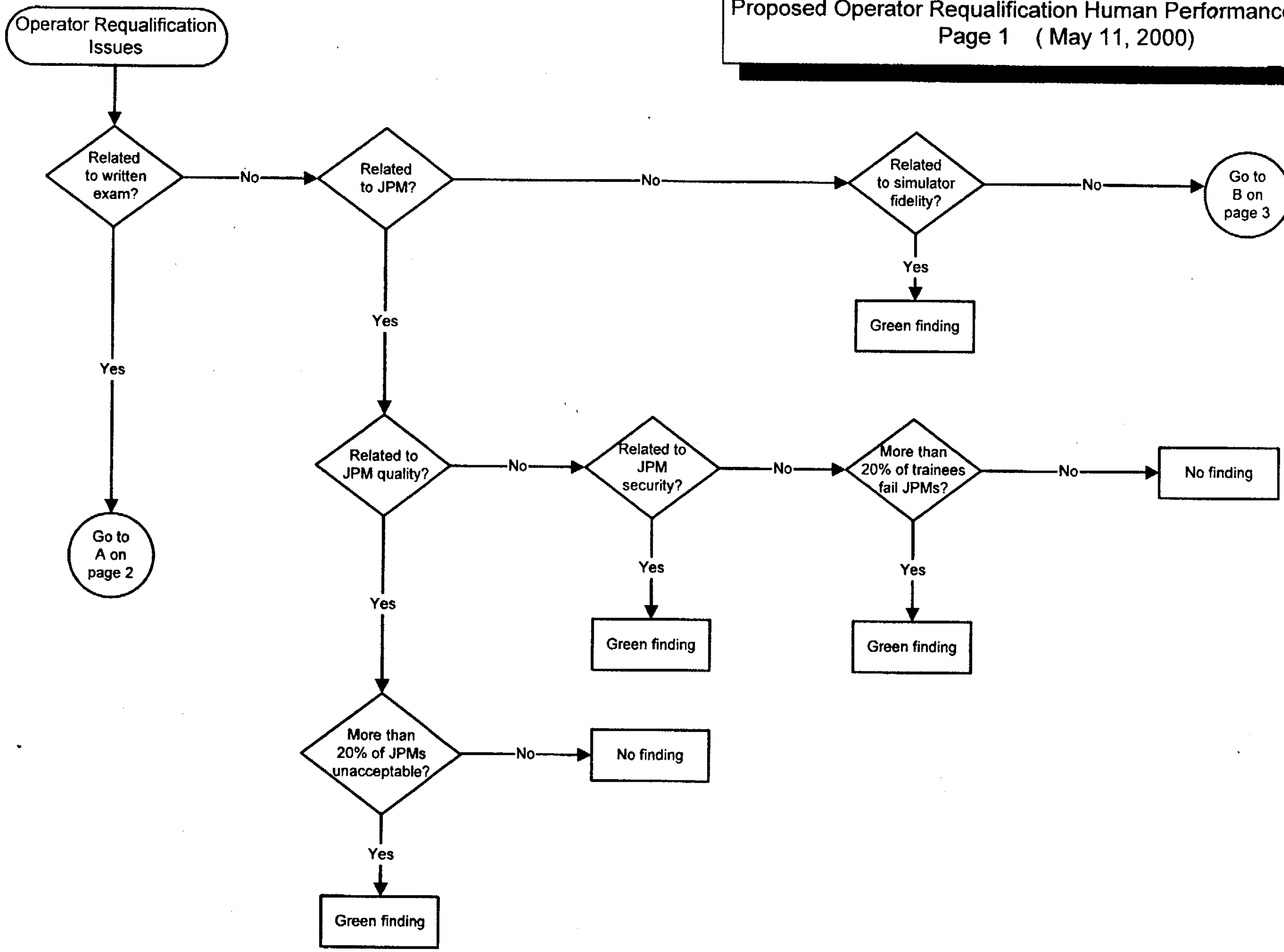
Number of Crews with UNSAT Performance in the Annual Operating Test

Number of Crews that took the Annual Operating Test (Includes Dual Units)

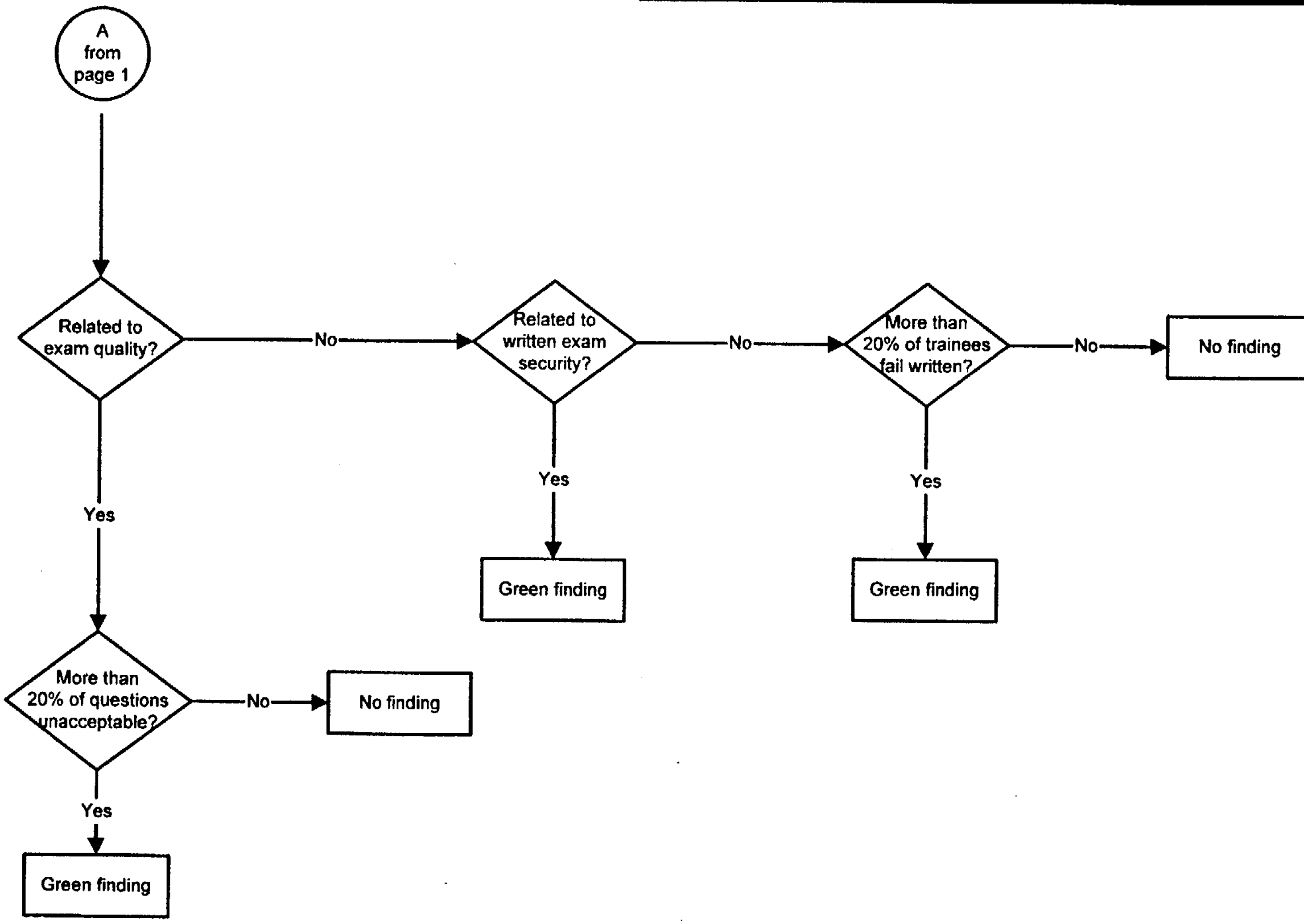
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|
| 4 | G | W | Y | R | NA | NA | NA | NA |
| 5 | G | W | Y | R | R | NA | NA | NA |
| 6 | NF | G | W | Y | R | R | NA | NA |
| 7 | NF | G | W | Y | Y | R | R | NA |
| 8 | NF | G | W | W | Y | Y | R | R |
| 9 | NF | G | G | W | Y | Y | R | R |
| 10 | NF | G | G | W | W | Y | Y | R |
| 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 - 33% Failure Rate
W = 34 - 50% Failure Rate (NUREG-1021, Rev 8 - UNSAT Requal Program)
Y = 51 - 75% Failure Rate
R = >75% Failure Rate
NA = Not Applicable

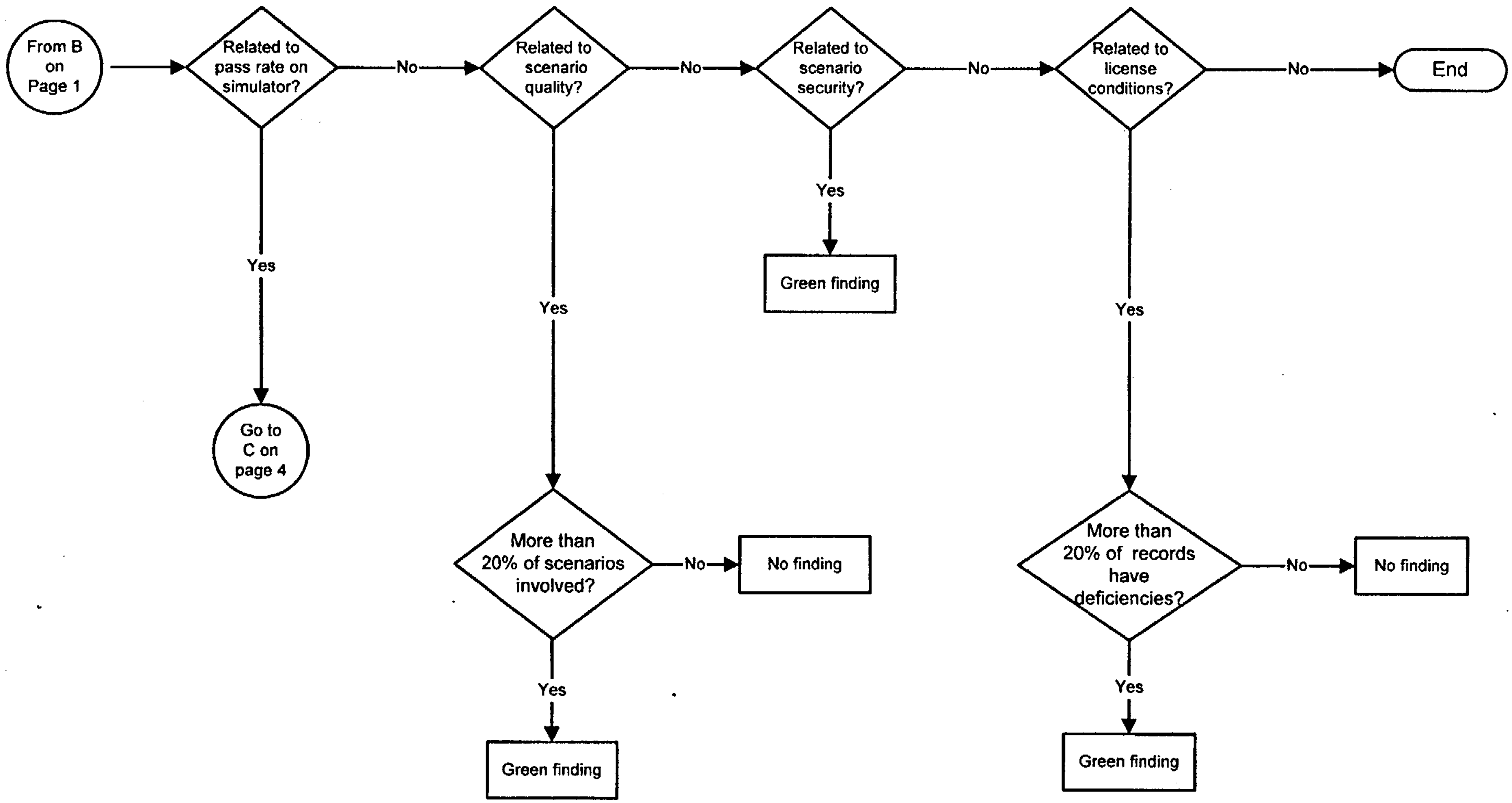
# Proposed Operator Requalification Human Performance SDP
Page 1 ( May 11, 2000)



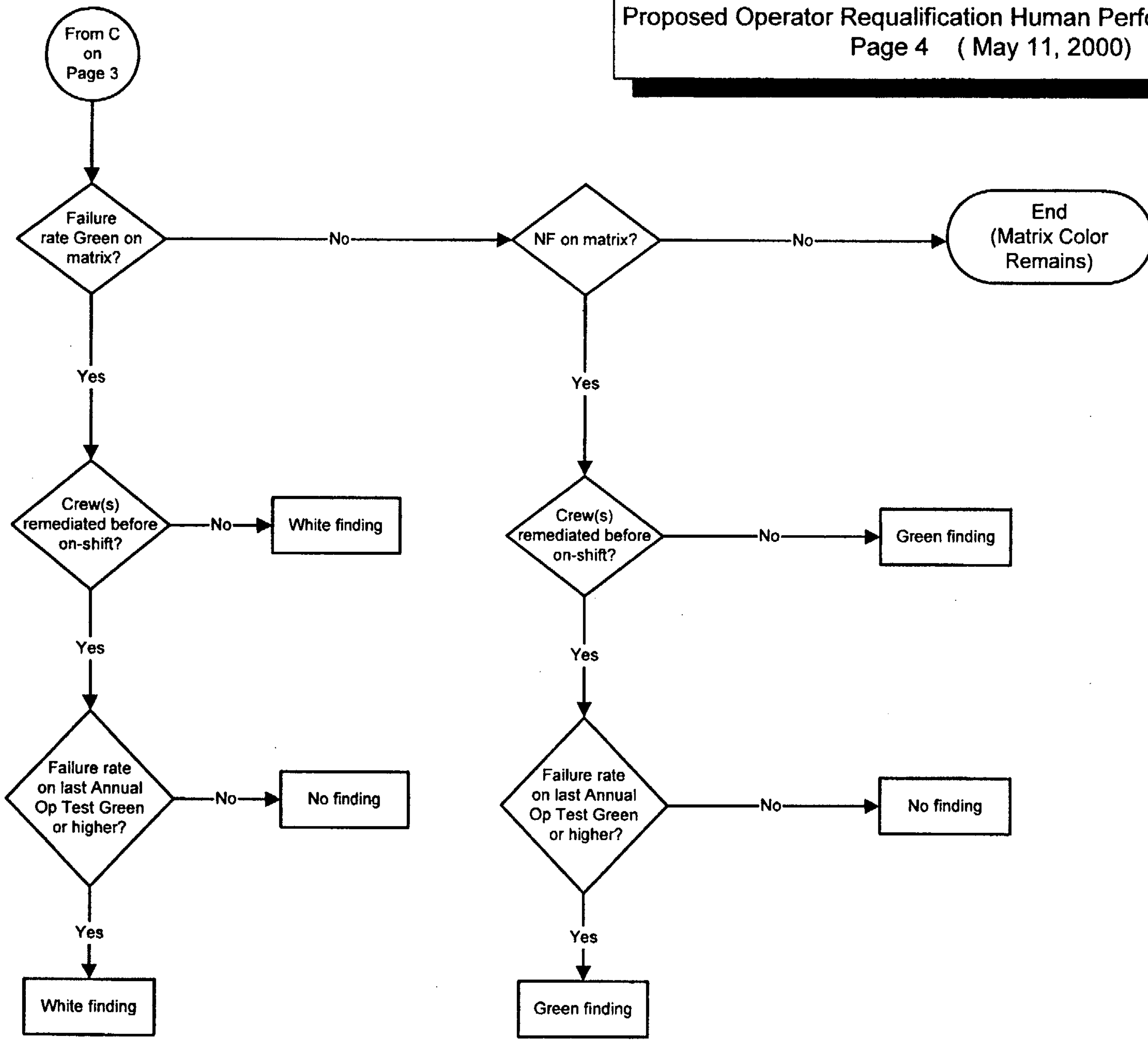
Proposed Operator Requalification Human Performance SDP
Page 2 ( May 11, 2000)



Proposed Operator Requalification Human Performance SDP
Page 3 ( May 11, 2000)



# Proposed Operator Requalification Human Performance SDP
Page 4 ( May 11, 2000)



(assuming a breach) focus on public and occupational doses that occur as a result of the loss of control of package contents. These are actual doses to real individuals, and depending on the level, would lead to either YELLOW or RED findings. Note that for a member of the public, the dose would in almost all cases be an estimate. Designated on-scene trained responders (e.g., local county Hazmat emergency team) would be designated occupational workers, subject the occupation dose limits.

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The greater-than-Type A branch provides for a YELLOW finding, assuming no loss of control of package contents. A RED finding would result if package contents control was lost. An example of a YELLOW finding is where a receiving facility finds the incoming shipment (irradiated components) package's drain valve on the package open -- a direct pathway to environment, but no potential for loss of control of materials (assuming normal conditions of transport). A RED finding is appropriate for the same "open valve" scenario if the package contents were spent fuel -- fission product gases released continuously to the environs during the shipment, assuming normal conditions of transport. However, in the event of a transportation accident that led to loss of fuel integrity, public dose consequences could exceed acceptable levels before adequate protective measures could be implemented.

Low Level Burial Ground Access

Nuclear power plants ship low-level waste (LLW) to licensed LLW burial grounds. These facilities (typically licensed by the host State) have the responsibility and authority to grant access to licensees for disposal of LLW. These LLW burial grounds have specific disposal criteria (aside from DOT/NRC shipping regulations) that licensees must meet (e.g., Waste Characterization, Part 61.56). In the past, some NRC licensees did not meet the acceptance standards of the LLW burial ground, and were issued temporary bans (i.e., the burial ground would not accept LLW from non-compliant licensees for extended time periods). As the receiving party, the LLW burial facilities are required to inspect for certain non-compliances with shipping regulations. Repeated failures to meet these and the disposal grounds requirements can weigh in on the LLW facilities decision to prohibit access to the LLW burial site. While recent NRC licensee performance has been excellent, if a licensee is banned for an extended period of time (typically one month, based on repeated performance failures and shortcomings), the finding is YELLOW.

Part 61 Finding

If a licensee ships waste and it is determined that the waste was under-classified, contrary to the requirements of 10 CFR Part 61.55 (e.g., waste classified at Class A, but later found to be Class B), then the finding is WHITE.

REPLACE w/ A

Attachment 4

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A

Part 61 Finding

If a licensee ships Class C or greater waste and it is determined that the waste was under-classified, contrary to the requirements of 10 CFR 61.55 (e.g., waste classified as Class A or Class B, but later found to be Class C or greater), then the finding is WHITE. In addition, if a licensee ships Class A or Class B waste and it is determined that the waste was under-classified, contrary to the requirements of 10 CFR Part 61.55 (e.g., waste classified as Class A, but later found to be Class B), and resulted in the improper disposal of the waste, contrary to the requirements of 10 CFR Part 61.56, then the finding is WHITE. If the under-classification of Class A or Class B waste did not result in the improper disposal of the waste (i.e., not resulting in an actual increase in risk), then the finding is GREEN.

Determination of under-classification of waste is made by the applicable regulatory authority for the waste disposal facility.

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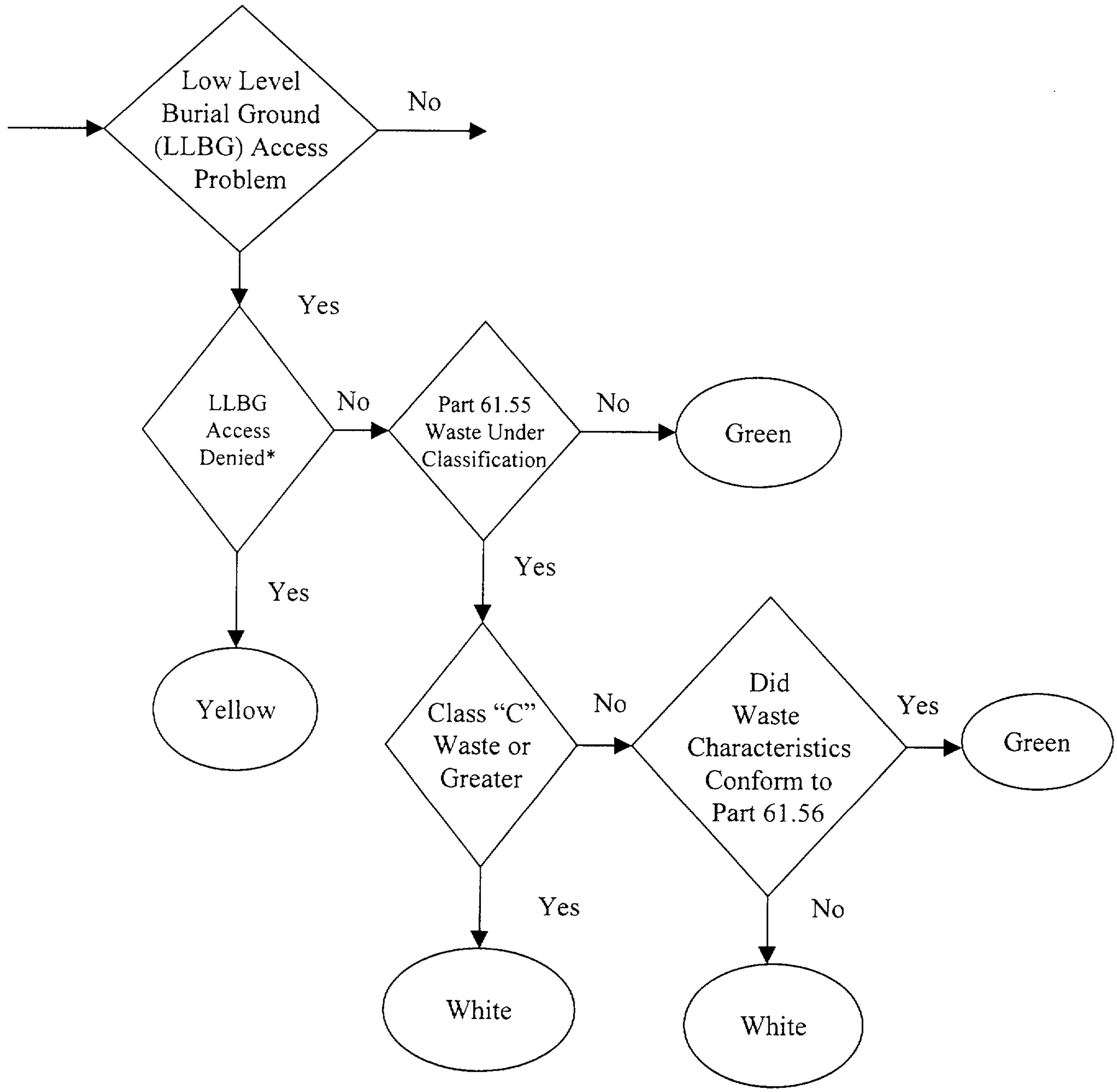
# Low level Burial Ground



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Failure to Make Notifications or Provide Emergency Information

This branch of the logic diagram focuses on vital communication and information, and notification requirements that must be provided by the licensee. Shippers of hazardous materials are required to provided emergency response information. Failure to provide these required notifications could seriously hamper or prevent the ability of the federal, state and local agencies to adequately respond as needed to transportation events and accidents. By hampering or preventing this regulatory response, the public health and safety could be negatively impacted, with an attendant loss of public confidence.

These requirements (in 49 CFR Part 172, Subpart G, Section 172.600) apply to any shipment which is required to have shipping papers. Shipments of excepted radioactive material packages (limited quantities, "empty" packages, etc) are not subject to the emergency response information.

NRC regulations (10 CFR 71.97) require advance notification to state governors for shipments of irradiated reactor fuel and nuclear waste under certain conditions. These notifications include quantity and form, and type of shipping container required. Notifications must be made in a timely manner to all the states hosting the radioactive material shipment. Additionally, 10 CFR 20.1906 requires receivers of certain packages of radioactive materials to perform timely external and surface contamination radiation monitoring upon receipt of the packages. If applicable radiation limits are exceeded, the receiving licensee must then report the event to the appropriate NRC Regional Office.

For Block N1 (10 CFR 71.97 non-compliance), if the licensee fails to make the required notifications before the shipment entered the State's boundary (crossed the State line) for interstate shipments, the finding would be WHITE. For intrastate shipments, if the shipment was put on public roads/rails before the Governor received the required notification, then a finding would be WHITE. Note that any other timeliness non-compliance (e.g., notification not postmarked at least 7 days before the 7 day shipment period), these findings would be GREEN.

For Block N2 (49 CFR 172.602 non-compliance), if the licensee fails to provide the required emergency response information to the shipment carrier (the shipment leaves the licensee's facility and control without the required information), the finding is WHITE. If the carrier misplaces or loses the ~~material~~ information (beyond the licensee's control), the finding is GREEN.

For Block N3 (49 CFR 172.604 non-compliance), if during an actual emergency the licensee does not respond in a timely manner in accordance with the requirements (or had not provided the 24-hour telephone number), the finding is WHITE.

For Block N4 (10 CFR 20. 1906), if the licensee's receipt surveys show 1) the package's external radiation levels in excess of the Part 71 limits, or 2) the surface radioactive contamination level in excess of five times the Part 71 (49 licensee — DRAFT —

CFR 173) limits, and the ~~facility~~ licensee fails to make an immediate report, then the finding is WHITE. Other non-compliances are GREEN.

Certificates of Compliance

Pursuant to 10 CFR 71.3, a licensee may not deliver or transport licensed material without a general or specific license. The general license for the use of an NRC-approved package is discussed in 10 CFR 71.12. Section 71.12 grants a general license to a licensee to transport or deliver to a carrier for transport, licensed material in a package for which a license, certificate of compliance (CoC), or other approval has been issued by the NRC. Additionally, Section 71.5 requires the licensee to comply with the applicable DOT regulations in 49 CFR.

Usually, the form of approval issued by the NRC is a CoC. For purposes of readability, consider the CoC as discussed here to mean any NRC issued approval for a package. The CoC approves a specific package design, including a detailed allowable contents description consistent with the use of the general license of Section 71.12. The CoC also lists the requirements or "conditions" for the use and maintenance of the package in block 4 of the CoC. Frequently, these conditions include references to the package's Safety Analysis Report (SAR) or procedures supplied by the CoC holder to the package owner or user. The user of the package must comply with the requirements of 10 CFR Part 71, the applicable regulations of 49 CFR, the CoC and their own transportation program instructions, including quality assurance requirements, to ship material.

Discussion

The following discussion provides a step-by-step description of the decision steps which make up the Certificate of Compliance (COC) portion of the Significance Determination Process (SDP) flowchart for Transportation & Part 61. It is anticipated that the inspector will have properly followed the Transportation and Part 61 SDP flowchart through the Radiation Limit Exceeded and Breach of Package decision points to the decision point where this COC branch begins. It is also expected that the inspector follows previous guidance concerning multiple findings on a single incident. That is, a finding with a package breach which resulted in a YELLOW determination and a CoC deficiency which resulted in a GREEN determination, would be considered to be a YELLOW finding. This is because the YELLOW signifies a more serious problem with the package breach aspect of the finding, than the CoC deficiency aspect of the finding.

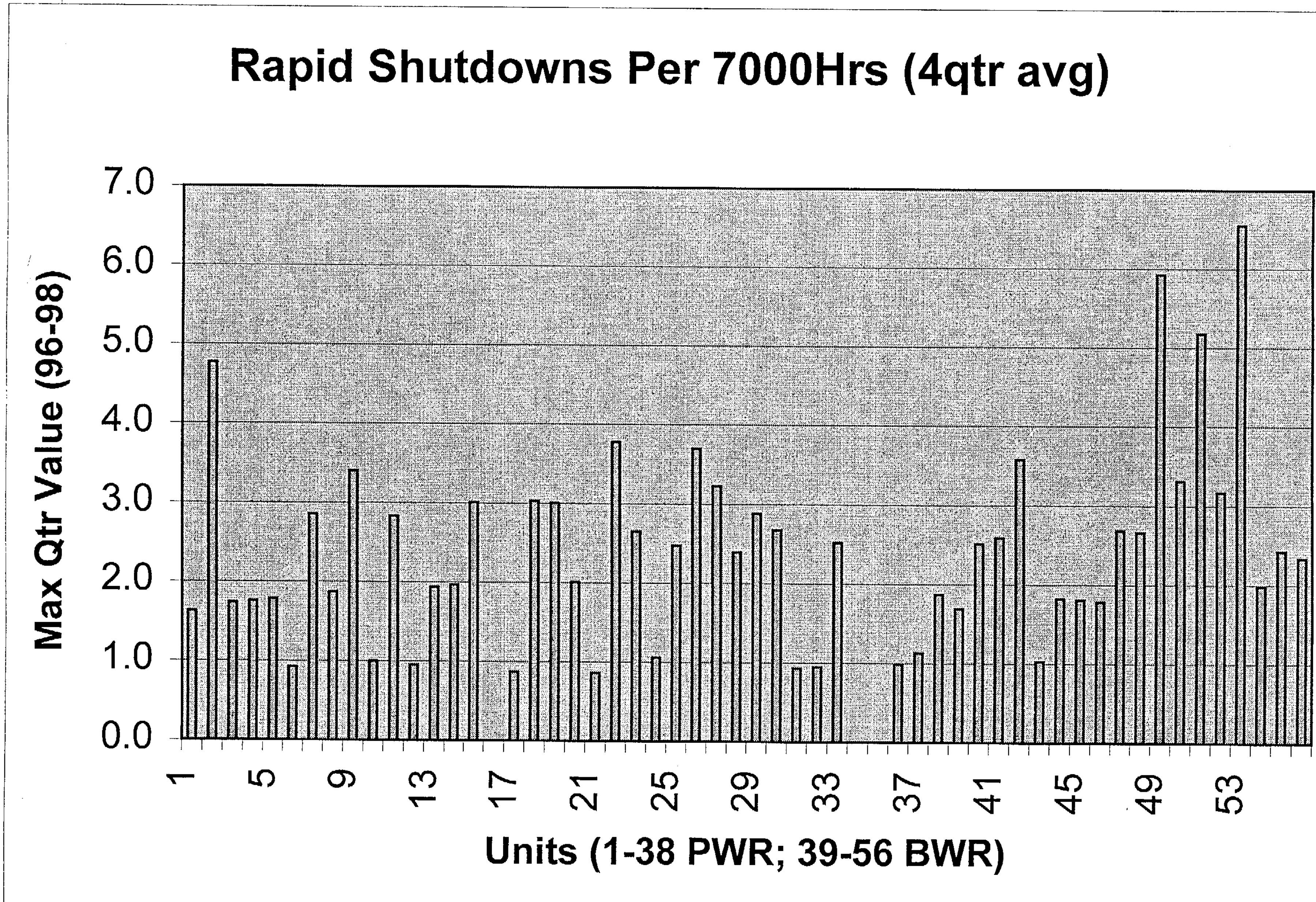
This branch of the logic diagram resolves an NRC, or licensee, identified finding that deals with package preparation, use and maintenance. It includes a noncompliance with a CoC specification(s) or condition(s) for a transportation package/cask. The following is a list of all the decision blocks contained in the COC SDP flowchart for Transportation & Part 61.

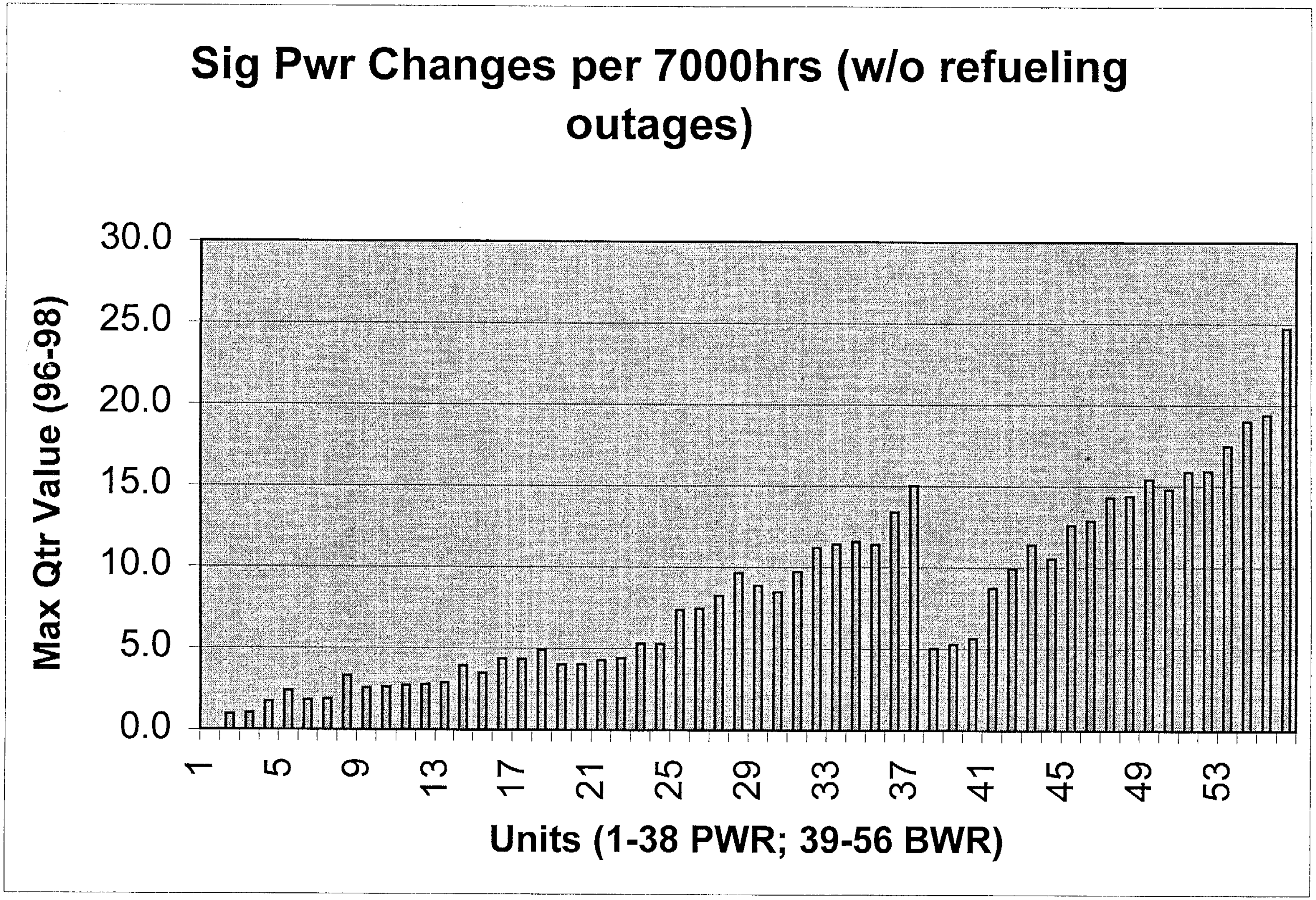
## Industry Perspectives on Unplanned Power Change Indicator

- Original indicator showed a strong correlation with plants that had recognized performance issues.
- The development of the original indicator was based on data that counted when a plant had to respond to a condition prior to a weekend (one to five days).
- The indicator in the program was revised to three days based on industry assessment that this was a reasonable planning period to brief operators and maintenance crew, check for spare parts and vendor information and schedule the work in an orderly fashion.
- The thresholds were adjusted based on industrywide data submitted in January 2000.
- NRC has expressed a concern for potential unintended consequences of a plant trying to live with a problem to get beyond the 72 hour period.
- NRC asked industry to evaluate changing the indicator to count all power changes for simplicity and compensate for the greater count through a change in the threshold.
- The industry has expressed concerns with the current and proposed indicator in that preventive and pre-emptive maintenance activities that improve plant reliability may not be conducted so as to avoid a count. As the industry moves toward deregulation, some executives believe more frequent power reductions will be made during low power demand periods to improve reliability during high power demands when revenues are greater.
- The NEI task force has collected data from approximately half of the industry that identifies all power changes greater than 20% during 1996 to 1998. Data based on the NRC daily operating summary was found to be incomplete. The actual data yields the following results:
  - PWRs had an average of 11.63 counts versus an average of 27.68 for BWRs
  - 36% of the BWR counts resulted from control rod adjustments
  - BWR design differences cause a range of rod alignment counts from 1 to 26
  - 26% of the PWR counts resulted from turbine valve testing
  - The PWR turbine testing counts is also design specific and occurred at only 33% of the units
  - When other exclusions for proper plant actions are included (required surveillances, pump swapping to equalize run hours, routine water box back-flushing, etc.) 51% of the BWR counts and 34% of the PWR counts are for legitimate plant operations reasons and not consistent with the intent of the indicator.
- Based on our review of the data, the industry recommends keeping the indicator as it currently exists for the following reasons:
  - Plant design differences create an uneven playing field not indicative of plant performance
  - Varying design conditions make it impossible to establish uniform thresholds

Attachment 5

- Overcoming the design differences would create a substantial list of exceptions that would complicate the guidance
- There is no firm evidence that plants are managing the indicator as feared by either the industry or the NRC. The 72 hour planning period provides a balance between maintaining reliability yet identifying plants with performance problems that warrant action.
- The current indicator has shown a strong correlation to plants with recognized performance issues.
- The proposed new indicator would only be different – not better
- Any identified impacts from deregulation should be assessed for future changes to the PI.


Rapid Shutdowns Per 7000Hrs (4qtr avg)
Max Qtr Value (96-98)
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
1
5
9
13
17
21
25
29
33
37
41
45
49
53
Units (1-38 PWR; 39-56 BWR)



Sig Pwr Changes per 7000hrs (w/o refueling outages)
Max Qtr Value (96-98)
30.0
25.0
20.0
15.0
10.0
5.0
0.0
1
5
9
13
17
21
25
29
33
37
41
45
49
53
Units (1-38 PWR; 39-56 BWR)

SIGNIFICANT POWER CHANGES
TOTALS FOR 1996 TO 1998 (EXCLUDING SHUTDOWNS FOR REFUELING)

**PWRs**

| UNIT | TOTAL | TB TEST | LOAD REJECT | WATER BOX | ROD TEST | HURRICANE | SURV TEST |
|---|---|---|---|---|---|---|---|
| ABC | 12 | | | | | | |
| D | 4 | | | | | | |
| EF | 12 | | | | | | |
| G | 32 | 11 | 2 | | | | |
| H | 30 | 12 | | | | | |
| I | 30 | 22 | | | | | |
| J | 27 | 24 | | | | | |
| K | 9 | | | | 3 | | |
| L | 8 | | | | 1 | | |
| MN | 6 | | | | | | |
| O | 5 | | | | | | |
| PQRS | 52 | 10 | | 4 | | 2 | |
| T | 12 | | | | | | |
| U | 4 | | | | | | |
| V | 8 | | | | | | |
| W | 5 | | | | | | |
| X | 7 | | | | | | 1 |
| Y | 13 | | | | | | 2 |
| Z | 24 | 2 | | 8 | | | |
| AA | 14 | | | 3 | | | |
| **TOTALS** | **314** | **81** | **2** | **15** | **4** | **2** | **3** |

SIGNIFICANT POWER CHANGES
TOTALS FOR 1996 TO 1998 (EXCLUDING SHUTDOWNS FOR REFUELING)

BWR's

| UNIT | TOTAL | ROD ADJUST | WATER BOX | MSIV TEST | TB VALVE | SURV TEST | PUMP SWAP |
|---|---|---|---|---|---|---|---|
| A | 13 | 5 | 2 | | | | |
| B | 15 | 6 | 2 | | | | |
| C | 35 | 26 | | | | | |
| D | 12 | 7 | | | | | |
| E | 42 | 8 | 21 | | | | |
| F | 21 | 1 | | 8 | | | |
| GH | 65 | 25 | 4 | | 5 | | |
| I | 32 | 12 | 3 | | | | |
| J | 39 | 13 | 5 | | | | |
| K | 10 | 3 | | | | | |
| L | 16 | 7 | | | | 3 | 1 |
| M | 34 | 2 | | | | 1 | 1 |
| N | 24 | 1 | | | | 7 | 2 |
| O | 26 | 10 | | | | 10 | 2 |
| P | 32 | 14 | | | | | |
| Q | 29 | 11 | | | | | |
| R | 35 | 18 | | | | | |
| S | 46 | 21 | | | | | |
| **TOTALS** | **526** | **190** | **37** | **8** | **5** | **21** | **6** |

 (NEI Proposal)

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# 2 PERFORMANCE INDICATORS

## 2.1 INITIATING EVENTS CORNERSTONE

The objective of this cornerstone is to measure the frequency of those events that upset plant stability and challenge critical safety functions, during shutdown as well as power operations. If not properly mitigated, and if multiple barriers are breached, a reactor accident could result which may compromise the public health and safety. Licensees can reduce the likelihood of a reactor accident by maintaining a low frequency of these initiating events. Such events include reactor shutdowns due to turbine trips, loss of feedwater, loss of off-site power, and other significant reactor transients.

The indicators for this cornerstone are reported and calculated per reactor unit.

There are three indicators in this cornerstone:

- Conditions requiring rapid reactor shutdowns per 7,000 critical hours
- Conditions requiring rapid reactor shutdowns with a loss of normal heat removal per 12 quarters
- Unplanned Power Changes per 7,000 critical hours

### CONDITIONS REQUIRING RAPID REACTOR SHUTDOWNS PER 7,000 CRITICAL HOURS

**Purpose**

This indicator monitors the number of times plant conditions required a rapid shutdown of the reactor. It measures the rate of rapid shutdowns per year of operation at power and provides an indication of initiating event frequency.

**Indicator Definition**

The number of occurrences of conditions requiring rapid shutdown of the reactor during the previous four quarters while critical per 7,000 hours.

**Data Reporting Elements**

The following data is reported for each reactor unit:

- the number of occurrences of conditions requiring rapid shutdown of the reactor while critical in the previous quarter

- the number of hours of critical operation in the previous quarter

Attachment 6

## Calculation

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

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

## Definition of Terms

*Rapid shutdowns* are those that bring the reactor from a critical condition at some power level to a subcritical condition within 15 minutes of the onset of conditions that require a rapid shutdown.

*Onset of conditions requiring rapid shutdown* are those situations in which: (a) plant parameter(s) exceeds or is about to exceed a reactor protective system setpoint, (b) plant parameters reach levels at which plant procedures require a rapid shutdown, or (c) human error or equipment failure cause rapid shutdown.

*Criticality,* for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a rapid shutdown after the reactor is critical—this condition would count as a condition requiring a rapid shutdown of the reactor.

## Clarifying Notes

The value of 7,000 hours is used because it represents one year of reactor operation at an 80.0% capacity factor.

If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is computed as N/A because rate indicators can produce misleadingly high values when the denominator is small. The data elements (unplanned rapid shutdowns and critical hours) are still reported.

Examples of the types of conditions requiring rapid reactor shutdowns that **are included**:

*Turbine Trip*
*Loss of Main Feedwater Flow*
*Loss of Normal Heat Sink (main condenser)*
*MSIV Closure*
*Loss of Offsite Power*

*Loss of Electrical Load (includes generator trip)*
*Excessive Feedwater (overcooling transient)*
*Loss of Auxiliary/Station Power*
*Small Loss of Coolant Accident (includes reactor/recirculation pump seal failures)*
*Loss of Service Water/Component Cooling Water*
*Loss of Vital AC/DC bus*
*Secondary/balance-of-plant Piping/Component Ruptures*
*Reactivity Control Anomaly (e.g., dropped or misaligned rod)*
*Other Initiators Leading to Automatic Actuation of Reactor Protection System*

BWR-specific Initiators:
*Reactor Pressure Regulator Failure*
*Unplanned Change Reactor Recirculation Flow*

PWR-specific Initiators:
*Loss of Reactor Coolant System Flow*
*Uncontrolled Rod Withdrawal*
*Steam Generator Tube Rupture*

Examples of rapid reactor shutdowns that **are not** included:

*Rapid shutdowns that are planned to occur as part of a test (e.g., a reactor protective system actuation test).*
*Rapid shutdowns that are part of a normal sequence of a planned shutdown or evolution.*
*RPS actuation signals that occur while the reactor is sub-critical*

**Frequently Asked Questions**

# CONDITIONS REQUIRING RAPID REACTOR SHUTDOWNS WITH A LOSS OF NORMAL HEAT REMOVAL

## Purpose

This indicator monitors that subset of conditions requiring rapid shutdown that necessitate the use of mitigating systems and are therefore more risk-significant than uncomplicated rapid shutdowns.

## Indicator Definition

The number of conditions requiring rapid shutdown of the reactor during the previous 12 quarters that also involved a loss of the normal heat removal path through the main condenser 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 conditions requiring rapid shutdown of the reactor while critical in the previous quarter in which the normal heat removal path through the main condenser was lost 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 rapid reactor shutdowns while critical in the previous 12 quarters in which the normal heat removal path through the main condenser was lost prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.

## Definition of Terms

*Loss of normal heat removal path:* decay heat cannot be removed through the main condenser when any of the following conditions occur:

- loss of main feedwater
- loss of main condenser vacuum
- closure of main steam isolation valves
- loss of turbine bypass capability

*Rapid shutdowns* are those that bring the reactor from a critical condition at some power level to a subcritical condition within 15 minutes of the onset of conditions that require a rapid shutdown.

*Onset of conditions requiring rapid shutdown* are those situations in which: (a) plant parameter(s) exceeds or is about to exceed a reactor protective system setpoint, (b) plant parameters reach levels at which plant procedures require a rapid shutdown, or (c) human error or equipment failure cause rapid shutdown.

*Criticality,* for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a rapid shutdown after the reactor is critical—this condition would count as a condition requiring a rapid shutdown of the reactor.

**Clarifying Notes**

Intentional operator actions to control the reactor cooldown rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator.

Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on a rapid reactor shutdown, are not counted in this indicator.

Partial losses of condenser vacuum in which sufficient capability remains to remove decay heat are not counted in this indicator.

This indicator includes conditions requiring rapid shutdown of the reactor in which the normal heat removal path through the main condenser was lost. The conditions counted for this indicator are also counted for the *Conditions Requiring Rapid Shutdown per 7000 Critical Hours* indicator.

Rapid 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.

Momentary operations of PORVs or safety relief valves are not counted as part of this indicator.

**Frequently Asked Questions**

MEMORANDUM TO: Chairman Meserve
Commissioner Dicus
Commissioner Diaz
Commissioner McGaffigan
Commissioner Merrifield

May 31, 2000

FROM: William D. Travers ***/RA by Carl J. Paperiello Acting for/***
Executive Director for Operations

SUBJECT: RESOLUTION OF MANUAL SCRAMS IN THE UNPLANNED SCRAM PERFORMANCE INDICATOR

In its March 28, 2000, Staff Requirements Memorandum approving initial implementation of the revised reactor oversight process, the Commission directed the staff to expeditiously report back to the Commission with a discussion of potential resolutions and schedules on the issue of including manual scrams in the unplanned scram performance indicator (PI). This memorandum provides the requested information.

The staff held a public meeting with the Nuclear Energy Institute (NEI) and other external stakeholders on March 29, 2000, to obtain additional information the staff should consider related to counting manual scrams. At that meeting, the NRC committed to use a formal process to consider, on a priority basis, an alternate PI(s) that tracks events in a way that minimizes potential unintended consequences. This formal process will include methods to obtain and consider public feedback similar to those employed during the development of the Revised Reactor Oversight Process. NEI agreed to submit a proposal for an alternate PI(s) for initiating events for the staff to consider.

In regularly scheduled NRC/NEI public working group meetings, the staff has held preliminary discussions about potential changes to initiating event PIs. The concept currently under consideration by NEI is to develop one or more indicators that count the number of events or conditions that result in a nuclear power plant changing power for reasons other than routine operational requirements. The details of how this can be accomplished are under development by NEI and are to be presented to the NRC at the next periodic public meeting between NRC and NEI on June 14. The proposed schedule, which has been discussed with NEI in previous meetings, is attached.

Attachment: As stated

CONTACT: D. E. Hickman, NRR/DIPM/IIPB
(301) 415-8541

cc: SECY
OGC
OCA
OPA
CFO
CIO

SCHEDULE FOR DEVELOPING AND IMPLEMENTING
IMPROVED INITIATING EVENTS CORNERSTONE
PERFORMANCE INDICATORS

| | |
|---|---|
| Draft proposed guidance for new indicator(s) | 6/14/00 |
| Finalize guidance | 7/14/00 |
| Collect data, establish thresholds, benchmark indicator(s) | 7/17 - 9/30/00 |
| Conduct pilot program and solicit public comment | 10/1/00 thru 3/31/01 |
| Analyze results and public comment | 4/1 - 4/30/01 |
| Make final decision | 5/1/01 |
| Train staff and industry (if needed) | 5/1 - 5/31/01 |
| First reports submitted with revised indicators if applicable | 7/21/01 |

6/5/00
PROPOSE
Change (p.11)
And
Comments

# NRC INSPECTION MANUAL

IIPB

MANUAL CHAPTER 0305

## OPERATING REACTOR ASSESSMENT PROGRAM

DRAFT

### 0305-01 PURPOSE

The Revised Reactor Oversight Process is the result of an effort by the NRC to improve the NRC's inspection, assessment, and enforcement programs. The result is a regulatory framework (exhibit 1) that is more objective, understandable, and predictable and focuses agency resources on areas that have the greatest impact on safe plant operation. The Operating Reactor Assessment Program evaluates the overall safety performance of operating commercial nuclear reactors and communicates those results to licensee management, members of the public, and other government agencies.

The assessment program (exhibit 2) collects information from the inspection program and performance indicators in order to enable the agency to arrive at objective conclusions about the licensee's safety performance. Based on this assessment information, the process determines the appropriate level of agency response including supplemental inspection, demands for information, confirmation of specific corrective actions, or orders, up to and including a plant shutdown. The assessment information and agency response are then communicated to the public. Follow-up agency actions, as applicable, are conducted to ensure that the corrective actions designed to address performance weaknesses were effective.

### 0305-02 OBJECTIVES

02.01 To collect information from inspection findings and performance indicators.

02.02 To arrive at an objective assessment of licensee safety performance using performance indicators and inspection findings.

02.03 To assist NRC management in making timely and predictable decisions regarding appropriate agency actions used to oversee, inspect, and assess licensee performance.

02.04 To provide a method for informing the public and soliciting stakeholder feedback on the NRC's assessment of licensee performance.

02.05 To provide a process to follow up on areas of concern.

### 0305-03 APPLICABILITY

This manual chapter applies to all operating commercial nuclear reactors except those sites that are under IMC 0350, "Staff Guidelines For Assessment and Review of Plants That Are Not Under The Routine Reactor Oversight Process". The



Attachment 7

contents of this manual chapter do not restrict the NRC from taking any necessary actions to fulfill its responsibilities under the Atomic Energy Act of 1954 (as amended).

## 0305-04 DEFINITIONS

04.01 <u>Significance Determination Process (SDP)</u>. A risk characterization process that is applied to inspection findings such that the overall licensee performance assessment process can compare and evaluate the findings on a significance scale similar to the performance indicators.

04.02 <u>Degraded Cornerstone</u>. A cornerstone that has two or more white inputs or one yellow input.

04.03 <u>Repetitive Degraded Cornerstone</u>. A cornerstone that is degraded (2 white inputs or 1 yellow input) for five or more consecutive quarters.

04.04 <u>Multiple Degraded Cornerstones</u>. Two or more cornerstones are degraded in any one quarter.

04.05 <u>Inspection Finding</u>. As used in IMC 0610* "Inspection Reports", an observation that has been placed in context. Findings are assigned a color based on their risk significance as an outcome of the significance determination process. Listed below are the colors associated the risk significance of these findings:

> Green Findings - Issues that, while not desirable, represent very low safety significance.
> White Findings - Issues with low to moderate safety significance.
> Yellow Findings - Issues with substantial safety significance which would require the NRC to take additional actions.
> Red Findings - Issues with high safety significance and an unacceptable loss of safety margin which would result in the NRC taking significant actions that could include ordering the plant to be shutdown.

04.06 <u>Assessment Period</u>. A rolling 12 month period that contains 4 quarters of performance indicators and inspection findings.

ASSESSMENT PERIOD WOULD NOT CHANGE. PROPOSED CHANGE to "timeframe" IS CONSISTENT WITH NOTE.

> **Note: An inspection finding is normally carried forward in the assessment process for a total of four calender quarters. However, the inspection finding will not be removed from consideration of future agency actions (per the Action Matrix) until the identified weaknesses in the root cause evaluation have been corrected.**

04.07 <u>Annual Assessment Cycle</u>. The 12 month assessment period, April 1 through March 31, that culminates in a Commission briefing.

04.08 <u>Assessment Inputs</u>. As used in this manual chapter, assessment inputs are the combination of performance indicators and inspection findings for a particular plant that are combined in the assessment process in order to determine appropriate agency actions.

04.09 MC 0350 Process. As used in this manual chapter, an oversight process that oversees licensee performance, inspections, and restart efforts for plants with significant performance problems.

04.10 Safety-Conscious Work Environment. An environment in which employees feel free to raise safety concerns, both to their management and to the NRC, without fear of retaliation.

## 0305-05 RESPONSIBILITIES AND AUTHORITIES

05.01 Executive Director for Operations (EDO)

a. Oversees the activities described in this manual chapter.

b. Approves deviations from the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix.

05.02 Director, Office of Nuclear Reactor Regulation (NRR)

a. Implements the requirements of this manual chapter within NRR.

b. Develops assessment program policies and procedures.

c. Ensures uniform program implementation and effectiveness.

d. Concurs on all agency actions that deviate from the Regulatory Response and Degraded Cornerstone columns of the Action Matrix as described in section 06.01.e of this manual chapter.

05.03 Regional Administrators

a. Implements the requirements of this manual chapter within their respective regions.

b. Develops and issues Annual Assessment Letters to each licensee, which contain a concise assessment of licensee performance using information captured by performance indicators and NRC inspection findings.

c. Directs allocation of inspection resources within the regional office based on the Action Matrix.

d. Establishes a schedule and determines a suitable location for the annual public meeting with each licensee to ensure a mutual understanding of the issues discussed in the Annual Assessment Letter.

e. Suspends the end-of-year performance review for those plants that have been transferred to the Inspection Manual Chapter 0350 process.

f. Approves agency actions that deviate from the Regulatory Response and Degraded Cornerstone columns of the Action Matrix as described in section 06.01.e of this manual chapter.

g. Recommends deviations from the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix.

05.04 Chief, Inspection Program Branch

a. Develops program guidance.

b. Collects feedback from the regional offices and assesses execution of the Operating Reactor Assessment Program to ensure consistent application.

c. Recommends and implements improvements to the Operating Reactor Assessment Program.

## 0305-06 BASIC REQUIREMENTS

### 06.01 Assessment Process

Licensee performance is reviewed over a 12-month period through the reactor assessment process (exhibits 3 and 4). The assessment process consists of a series of reviews which are described below.

Each regional office will conduct an ongoing review of the performance of their assigned plants. Inspections are conducted on a continuous basis in accordance with IMC 2515 and performance indicators are reported quarterly by the licensee. Assessment activities occur at quarterly intervals. Resident inspectors and branch chiefs shall maintain a continuous awareness of plant performance. If an inspection finding is identified during the quarter that is risk significant (i.e. greater than green) the regional office may address this issue without waiting until the end of the quarter, if appropriate. With respect to performance indicators, there is no intention that performance indicators be monitored on a real time basis. However, the regional office may take the appropriate action if the licensee contacts the regional office regarding a performance indicator that will definitively cross the green/white threshold at the end of the quarter. Additionally, the agency will not wait until the annual Agency Action Review meeting to address plants with significant performance problems. Plants with significant performance problems are those plants that are in the Multiple/Repetitive Degraded Cornerstone column or the Unacceptable Performance column of the Action Matrix.

The inspectors will normally use the SDP to evaluate inspection findings. However, the NRC enforcement policy also describes violations which the SDP process can not evaluate for risk significance (i.e., violations that involve actual safety significance, impede the regulatory process, or involve willfulness). This aspect of the enforcement policy shall be followed for violations outside of the SDP process. Regional management should notify the licensee in writing if additional inspection activities are scheduled to occur within the current quarter via an Assessment Follow-Up Letter (exhibit 7). * Not IMACTED BY PROPOSED CHANGE ALIGNED W/ PI RESULTS

a. Quarterly Review. The quarterly review utilizes PI data submitted by licensees and inspection findings compiled over the previous twelve months (which includes three new months of assessment inputs). This review will be conducted after the conclusion of each quarter during the annual assessment cycle. The regional office will review these results to determine appropriate agency actions per the Action Matrix. The most recent performance indicators and inspection findings shall be considered in determining agency action. This may include previous inspection findings as these findings are normally carried forward in the assessment process for four consecutive quarters.

   The responsible DRP Branch Chief will review the most recently submitted PIs (which should be submitted 21 days after the end of the quarter) and the inspection findings contained in the plant issue matrix (PIM) to identify any changes in performance trends. The review should be completed within five weeks of the end of the quarter. The BC shall utilize the Action Matrix to identify the potential scope of NRC actions not already embedded in the existing inspection plan. The regional office will notify the licensee via an Assessment Follow-Up Letter when assessment input thresholds are crossed. The Assessment Follow-Up Letter should be issued within two weeks of completing the quarterly review, if applicable. The regional office should still perform the supplemental inspection procedure even if a performance indicator re-enters the green band.

Additionally, for plants whose performance is in the Multiple/Degraded Cornerstone column of the Action Matrix consideration shall be given at each quarterly review for engaging senior licensee and agency management in discussions associated with 1) transferring the plant to the IMC 0350 process and 2) declaring licensee performance to be unacceptable in accordance with the guidance contained within this manual chapter.

**Note: If the agency determines that a licensee's performance is unacceptable then a shutdown order will be issued.**

* NOT IMPACTED SINCE EVENT IS IN REPORT AND POSTED MINIMUM ONE QTR.

b. Mid-Cycle Review. The mid-cycle review utilizes the most recent performance indicators and inspection findings compiled over the previous twelve months. This review incorporates activities from the quarterly review after the conclusion of the second quarter of the annual assessment cycle. The output of this review is a Mid-Cycle Letter (exhibit 8) instead of an Assessment Follow-Up Letter. Additional activities include planning inspection activities for the next twelve months as well as discussing any insights into potential cross-cutting issues (problem identification and resolution, human performance, and safety-conscious work environment).

c. A Mid-Cycle Review Meeting. Will be chaired by a Division of Reactor Projects (DRP) or Division of Reactor Safety (DRS) Division Director (DD). The DRP Branch Chiefs responsible for their plants should take the lead in presenting the overall results of the review to the Division Director. The DRS Branch Chiefs shall coordinate with the appropriate DRP Branch Chiefs to provide adequate support for the presentation and the development of the inspection plan. Other participants shall include applicable regional and resident inspectors, a Senior Reactor Analyst, a representative from the Inspection Program Branch (IIPB), the regional Allegations Coordinator or the Agency Allegations Advisor, and any other additional resources deemed necessary by the regional offices. The Action Matrix will be used to determine the scope of agency actions in response to the assessment inputs. The Mid-Cycle Review will be completed within six weeks of the end of the second quarter of the end of the annual assessment cycle.

The outputs of the mid-cycle review is a Mid-Cycle Letter (exhibit 8) and shall be issued within three weeks of the completion of the mid-cycle review. This letter shall contain:

* LOGIC IS CONSISTENT AND DOCUMENT

1. A summary of performance indicators and inspection findings that were outside of the licensee response band (including any associated cross-cutting issues) for the most recent quarter as well as discussion of <u>previous action taken by the licensee and the agency.</u> Performance issues from previous quarters may be discussed if:

(a) The agency's response to an issue had not been adequately captured in previous correspondence to the licensee.

CONSISTENT

(b) These issues, when combined with assessment inputs from the most recent quarter, result in increased regulatory action per the Action Matrix that would not be apparent from reviewing only the most recent quarter's results.

2. A qualitative discussion of distinct adverse trends as indicated by substantial cross-cutting issues that have not resulted in performance indicators or inspection findings outside of the licensee response band. Safety-conscious work environment issues shall only be discussed if the agency has previously engaged the licensee via a meeting or correspondence regarding a potential or actual "chilled work environment".

3. A statement of any actions, beyond the baseline inspection program, to be taken by the agency as well as any actions previously taken by the licensee.

4. An inspection plan for the next twelve months that will be updated (as necessary) at the End-of-Cycle Review meeting.

d. <u>End-of-Cycle Review</u>. The End-of Cycle Review is a comprehensive assessment of licensee performance using the most recent performance indicators and inspection findings from the previous 12 months. This review incorporates activities from the quarterly review after the conclusion of the annual assessment cycle. The output of this review is an Annual Assessment Letter (exhibits 9,10,11, and 12) instead of an Assessment Follow-Up Letter. Additional activities include planning inspection activities for the next twelve months, discussing any insights into cross-cutting issues (problem identification and resolution, human performance, and safety-conscious work environment), and providing an input into the Agency Action Review Meeting.

The End-of-Cycle Review Meeting will be chaired by the Regional Administrator or his/her designee. The DRP and DRS Division Directors (or designees) will present the results of the annual review. The Director of NRR (or another member of the Executive Team) should attend the meeting to provide the program office's perspective. Other participants should include DRP and DRS Branch Chiefs, Senior Reactor Analysts (SRAs), a representative from the Inspection Program Branch (IIPB), the regional Allegations Coordinator or the Agency Allegations Advisor, and senior representatives from the Division of Licensing Project Management, Office of Investigations, Office of Enforcement, and Office of Research. The End-Of-Cycle meeting should be held within six weeks of the end of the assessment cycle. The Action Matrix will be used to determine the scope of agency actions in response to assessment inputs.

The output of the End-of-Cycle Review is the Annual Assessment Letter (exhibits 9,10,11,and 12). This letter will be issued within one week after the Agency Action Review meeting and shall contain the following:

1. A statement regarding overall plant performance based on the most recent performance indicators and the previous 12 months of inspection findings.

2. A summary of any PIs or inspection findings that are currently outside of the licensee response band including a discussion of followup action taken by the licensee and the agency.

CONSISTENT

3. A brief summary of licensee performance that had been outside of the licensee response band for the first three quarters of the assessment cycle.

4. A qualitative discussion of adverse trends as indicated by substantial cross-cutting issues that have not resulted in performance indicators or inspection findings outside of the licensee response band. Safety-conscious work environment issues shall be discussed only if the agency has previously engaged the licensee via a meeting or correspondence regarding a potential or actual "chilled work environment".

5. A statement of any actions, beyond the baseline inspection program, to be taken by the agency as well as any actions previously taken by the licensee.

e. Agency Action Review. An Agency Action Review Meeting is conducted approximately two weeks after the End-of-Cycle Review by senior NRC managers and is chaired by the Executive Director for Operations (EDO) or designee. This review uses data compiled during the End-of-Cycle review and involves a collegial review by senior NRC managers and staff of the appropriateness of agency actions for plants with significant performance issues, overall industry performance, and the results of the oversight process self-assessment. Plants with significant performance weaknesses are those plants that are in the Multiple/Repetitive Degraded Cornerstone or Unacceptable performance column of the Action Matrix.

The Regional Administrators and the Director of NRR will brief the participants on overall industry performance, oversight process self-assessment results, and any plants with significant performance weaknesses as determined by the Action Matrix. The Agency Allegations Advisor, senior representative(s) from the Office of Nuclear Material Safety and Safeguards (NMSS), Office of Investigations, Office of Enforcement, Office of Research, Office of Public Affairs, Office of General Counsel, Office of the Chief Financial Officer, and Office of the Chief Information Officer will attend the meeting. All of the Annual Assessment Letters (exhibits 9,10,11, and 12) shall be sent to the licensee no later than one week after completing the Agency Action Review meeting to ensure that the annual assessment letters are publicly available prior to the Commission meeting.

f. Commission Meeting. Annually the EDO will brief the Commission to convey the results of the Agency Action Review Meeting to the Commission. The Commission should be briefed within eleven weeks of the end of the assessment cycle.

g. Action Matrix. The Action Matrix (exhibit 5) was developed with the philosophy that, within a certain level of safety performance (i.e., the licensee response band), the licensee should be allowed to address their performance issues. Agency action beyond the baseline inspection programs should occur only if assessment input thresholds are exceeded. The Action Matrix identifies the range of NRC and licensee actions and the appropriate level of communication for varying levels of licensee performance. The Action Matrix describes a graded approach in addressing performance issues. A few terms are used throughout the discussion of the Action Matrix. These are:

- *Regulatory Performance Meetings*. Regulatory performance meetings are held between licensees and the agency to discuss risk significant performance issues (i.e., outside of the licensee response band) that resulted in licensee performance outside of the licensee response band. Each risk significant assessment input shall be discussed in one of the forums listed below in order to arrive at a shared understanding of the performance issues, underlying causes, and planned licensee actions. These meetings may take place at a regulatory conference, periodic inspection exit meetings between the agency and the licensee, or public meetings. This meeting should be documented in an inspection report, a public meeting summary, or conference call minutes.

- *Licensee Action*. Anticipated actions by the licensee in response to the performance described in the appropriate column of the Action Matrix. If these actions are not being taken by the licensee then the agency may expand the scope of the applicable supplemental inspection to appropriately address the area(s) of concern. This would not be considered a deviation from the Action Matrix in accordance with section 06.01.e of this manual chapter.

- *NRC inspection*. The range of NRC inspection activities in response to the performance described in the appropriate column of the Action Matrix.

- *Regulatory actions*. Range of actions to be taken by the agency to in response to the performance described in the appropriate column of the Action Matrix.

Below is a discussion of the components of the Action Matrix. Refer to exhibit 5 for a depiction of the Action Matrix.

1. Response

   The Action Matrix lists expected NRC and licensee actions based on the inputs to the assessment process. Actions are graded such that the agency becomes more engaged as licensee performance declines. Listed below are the range of expected NRC and licensee actions for each column of the Action Matrix:

   - Licensee Response Column - All assessment inputs are green. The licensee will receive only the baseline inspection program and identified deficiencies will be placed into the licensee's corrective action program.

   - Regulatory Response Column - Assessment inputs result in one or two white inputs in different cornerstones. The licensee is expected to place the identified deficiencies in its corrective action program and perform an evaluation of the root and contributing causes. The licensee's evaluation will be reviewed during inspection procedure 95001 *Supplemental Inspection for One or Two White Inputs in a Strategic Performance Area*. Following completion of the inspection, the Branch Chief or Division Director should discuss the performance deficiencies and the licensee's proposed corrective actions with the licensee. The regulatory performance meeting will normally occur at an inspection exit meeting or a conference call between the licensee and the appropriate Branch Chief (or Division Director).

RESPONSE WOULD BE SUSTAINED

- <u>Degraded Cornerstone Column</u> - Assessment inputs result in a degraded cornerstone or 3 white inputs to any Strategic Performance Area. The licensee is expected to place the identified deficiencies in its corrective action program and perform an evaluation of the root and contributing causes for both the individual and the collective issues. The licensee's evaluation will be reviewed during inspection procedure 95002 *Supplemental Inspection For One Degraded Cornerstone Or Any Three White Inputs in a Strategic Performance Area*. Also, an independent assessment of the extent of condition will be performed by the region using appropriate inspection procedures chosen from the tables contained in Appendix B to Inspection Manual Chapter 2515. Following completion of the inspection, the Division Director or Regional Administrator should discuss the performance deficiencies and the licensee's proposed corrective actions with the licensee. The regulatory performance meeting will normally consist of a public meeting between the licensee and the appropriate Division Director (or Regional Administrator).

- <u>Multiple/Repetitive Degraded Cornerstone Column</u> -Assessment inputs result in a repetitive degraded cornerstone, multiple degraded cornerstones, multiple yellow inputs or a red input. The licensee is expected to place the identified deficiencies in its corrective action program and perform an evaluation of the root and contributing causes for both the individual and the collective issues. This evaluation may consist of a third party assessment. Inspection procedure 95003 *Supplemental Inspection for Repetitive Degraded Cornerstones. Multiple degraded Cornerstones, Multiple Yellow Inputs, or One Red Input* will be performed to determine the breadth and depth of the performance deficiencies. Following the completion of the inspection, the EDO or his designee, in conjunction with the Regional Administrator and the Director of NRR, will decide whether additional agency actions are warranted. These actions could include additional demands for information, confirmation of specific corrective actions, or orders, up to and including a plant shutdown. The regulatory performance meeting will normally consist of a public meeting between the licensee and the Regional Administrator (or Executive Director of Operations).

- <u>Unacceptable Performance Column</u> - Licensee performance is unacceptable and continued plant operation is not permitted within this column. In general, it is expected that entry into the multiple/repetitive degraded cornerstone column of the Action Matrix will precede plant consideration in the Unacceptable Performance Column. The Commission will meet with senior licensee management in a regulatory performance meeting to discuss the licensee's degraded performance and the corrective actions which will need to be taken before operation of the facility can be resumed. The NRC oversight of plant performance will also be placed under the guidance of IMC 0350. Unacceptable performance represents situations in which the NRC lacks reasonable assurance that the licensee can or will conduct its activities without undue risk to public health and safety. Examples of unacceptable performance may include:

  - Multiple significant violations of the facility's license, technical specifications, regulations, or orders.

- Loss of confidence in the licensee's ability to maintain and operate the facility in accordance with the design basis (e.g., multiple safety significant examples where the facility was determined to be outside of its design basis, either due to inappropriate modifications, the unavailability of design basis information, inadequate configuration management, or the demonstrated lack of an effective problem identification and resolution program).

- A pattern of failure of licensee management controls to effectively address previous significant concerns to prevent their recurrence.

| |
|---|
| **Note: If the agency determines that a licensee's performance is unacceptable then a shutdown order will be issued.** |

2. <u>Communication</u>. Communication between the licensee and the NRC is based on a graded approach. For declining licensee performance, higher levels of agency management will review and sign the assessment letters and conduct the annual public meeting.

3. <u>Supplemental inspection for a single white issue</u>. The regional office may elect not to conduct a supplemental inspection for a white finding that was identified as part of a licensee self-assessment activity. In deciding whether to exercise this option, the region should consider the results of past reviews of the licensee's problem identification and resolution program, specifically with regard to the effectiveness of previously performed root cause analyses. The DRP or DRS Division Director will authorize this option with the concurrence of the Inspection Program Branch Chief and should document the basis for the decision not to perform the supplemental inspection in an assessment follow-up letter to the licensee. This is not considered a deviation from the Action Matrix in accordance with section 06.01.e of this manual chapter.

   The purpose of this option is to provide an incentive for a licensees to aggressively pursue the identification and resolution of their own issues.

   OPTION SUSTAINED AND PROPOSED CHANGE CONSISTENT W/ PS.

4. <u>"Double-Counting" of performance indicators and inspection findings</u>. Some singular events may result in a simultaneous tripping of a performance indicator and an inspection finding. This would appear to result in two assessment inputs combining to cause increased regulatory action per the Action Matrix. For example, two white assessment inputs in the mitigating systems cornerstone would result in increased regulatory action per the degraded cornerstone column of the Action Matrix.

   Singular events should not be "double-counted" in the assessment program. However, the most conservative color from the performance indicator and the inspection finding (i.e. yellow vs. white) shall be used to determine the appropriate agency action according to the

Propose Change

Action Matrix. This is not considered a deviation from the Action Matrix as defined in section 06.01.e of this manual chapter.

5. Timeframe for "counting" inspection findings in the assessment program. The date used for consideration in the assessment program is the date of occurrence for events or the date of the end of the pertinent inspection period for inspection findings. After final determination of the significance of an inspection finding the regional office shall refer back to the appropriate date discussed above to determine if any additional action would have been taken had the significance of the inspection finding been known at that time.

Delete and add attached (1)

For example, the performance indicator for Unplanned Scrams was white (low to moderate risk significance) for the second quarter of the assessment cycle. Additionally, there was an inspection finding from the second quarter of the assessment cycle whose final risk significance was determined to be white (low to moderate risk significance) in the third quarter of the assessment cycle. In this case, the appropriate action would be to perform supplemental inspection procedure 950002 vice 95001 which would be documented in the Assessment Follow-Up Letter.

h. Deviations from the Action Matrix. There may be rare instances in which the actions dictated by the Action Matrix may not be appropriate. In these instances, the agency may deviate from the Action Matrix (which is described in section 06.01.d of this manual chapter) to either increase or decrease agency action. A deviation is defined as any actions taken that are inconsistent with the range of actions discussed in section 06.01.d of this manual chapter. A deviation from the Action Matrix requires the appropriate level of senior agency management approval and concurrence. The agency manager responsible for approval of the assessment letter one column to the right of where the licensee's performance is relative to the Action Matrix shall authorize the deviation. For example, if the agency will deviate from the Regulatory Response column of the Action Matrix, the appropriate approval level would be the Regional Administrator with the concurrence of the Director of NRR. Deviations from the Action Matrix shall be documented in the appropriate letter to the licensee (i.e. assessment follow-up letter, mid-cycle or annual assessment letter). The Executive Director for Operations shall authorize proposed deviations from the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix.

**Any deviations from the Action Matrix shall be documented in an annual report to the Commission.**

i. Relationship with the IMC 0350 Process and Unacceptable Performance. The normal criteria for considering a plant for the IMC 0350 process is 1) plant performance is in the Multiple/Repetitive Degraded Cornerstone column or the Unacceptable Performance column of the Action Matrix, (2) the plant is shutdown (whether voluntary or via an agency order to shutdown), and (3) an agency management decision is made to place the plant in the IMC 0350 process as discussed in IMC 0350. At this point, periodic assessment (quarterly, mid-cycle, and end-of-cycle) of licensee performance is no longer under the auspices of this manual chapter but is now under the IMC 0350 process. This process is more completely described in IMC 0350.

The normal criteria for declaring licensee performance to be unacceptable is 1) plant performance is in the Multiple/ Repetitive Degraded

ADD (A)

5. Timeframe for "counting" inspection findings in the Assessment program.

The date used for consideration in the assessment program is the date of occurrence for events (issues) or the date of the end of the pertinent inspection period for inspection findings. The event date should be used if the issue and corrective actions were identified in the licensee's corrective action program prior to the inspection within the assessment period. If the issue was discovered by the inspector during the inspection, the end of the pertinent inspection period should be used. However, the finding shall be recorded in the inspection report, and the significance shall be identified for no less than one quarter following issuance of the inspection report containing the identified finding. After final determination of the significance of an inspection finding the regional office shall refer back to the appropriate date discussed above to determine in any additional action would have been taken had the significance of the inspection finding been known at that time.

Using the actual issue or discovery date where corrective actions are identified and implemented, provides a consistent assessment timeframe in which to accurately implement the Action Matrix.

cornerstone column of the Action Matrix and 2) the criteria for the Unacceptable Performance column of the Action Matrix as described in section 06.01.d of this manual chapter.

The following are examples of the appropriate level of regulatory engagement between the agency and licensees once a plant has entered the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix:

1. Plant A continues to operate and regulatory engagement is dictated by the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix. The agency performs supplemental inspection procedure 95003 (if not already performed) and the plant remains under the level of oversight dictated by this manual chapter and is not transferred to the IMC 0350 process.

2. Plant B performs a voluntary shutdown to address performance issues. The agency performs supplemental inspection procedure 95003 (if not already performed) and issues a confirmatory action letter to document licensee commitments to the agency. The plant remains under the level of oversight dictated by this manual chapter and is not transferred to IMC 0350 process.

3. Plant C performs a voluntary shutdown to address performance issues. The entry conditions for IMC 0350 have been met and agency management determines that this process should be implemented using the criteria in IMC 0350. At this point, periodic assessment of licensee performance is no longer dictated by this manual chapter and is transferred to the IMC 0350 process. Plant performance is not determined to be unacceptable.

4. Plant D voluntarily shuts down to address performance issues. The agency determines that one of the criteria in paragraph 6.B.1 for unacceptable performance is met. The plant is considered to be in the Unacceptable Performance column of the Action Matrix and a shutdown order is issued by the agency. The plant is transferred to the IMC 0350 process.

5. Plant E is issued an order by the agency to shutdown. The licensee's performance is declared to be unacceptable and the plant will be transferred to IMC 0350.

j. Annual Meeting with Licensee

1. Scheduling

A public meeting with the licensee will be scheduled within 16 weeks of the end of the assessment period to discuss the results of the NRC's annual assessment of the licensee's performance. The 16 week requirement may occasionally be exceeded to accommodate the licensee's schedule. The meeting will be conducted onsite or in the vicinity of the site so that it will be accessible to members of the public. NRC management, as specified in the Action Matrix, will conduct the public meeting.

2. Meeting Preparation

The region shall notify those on distribution for the annual assessment letters of the meeting with the licensee. The region shall notify the media and State and local government officials of the issuance of the annual assessment letter and of the meeting with the licensee. Adequate notification of the meeting will be accomplished by distribution within at least 10 working days to the Public Document Room of the letter scheduling the meeting with the licensee.

3. Conduct of Licensee Meeting

The annual public meeting is intended to provide a forum for a candid discussion of issues related to the licensee's performance. NRC management, as specified in the Action Matrix, will discuss the agency's evaluation of licensee performance as documented in the annual assessment letter. The licensee should be given the opportunity to respond at the meeting to any information contained in the Annual Assessment Letter.

The annual meeting will be a public meeting. The meeting must be closed for such portions which may involve matters that should not be publicly disclosed under Section 2.790 of Title 10 of the Code of Federal Regulations (10 CFR 2.790). Members of the public, the press, and government officials from other agencies should be treated as observers during the conduct of the meeting. Attendees should be given the opportunity to ask questions of the NRC representatives at the conclusion of the meeting.

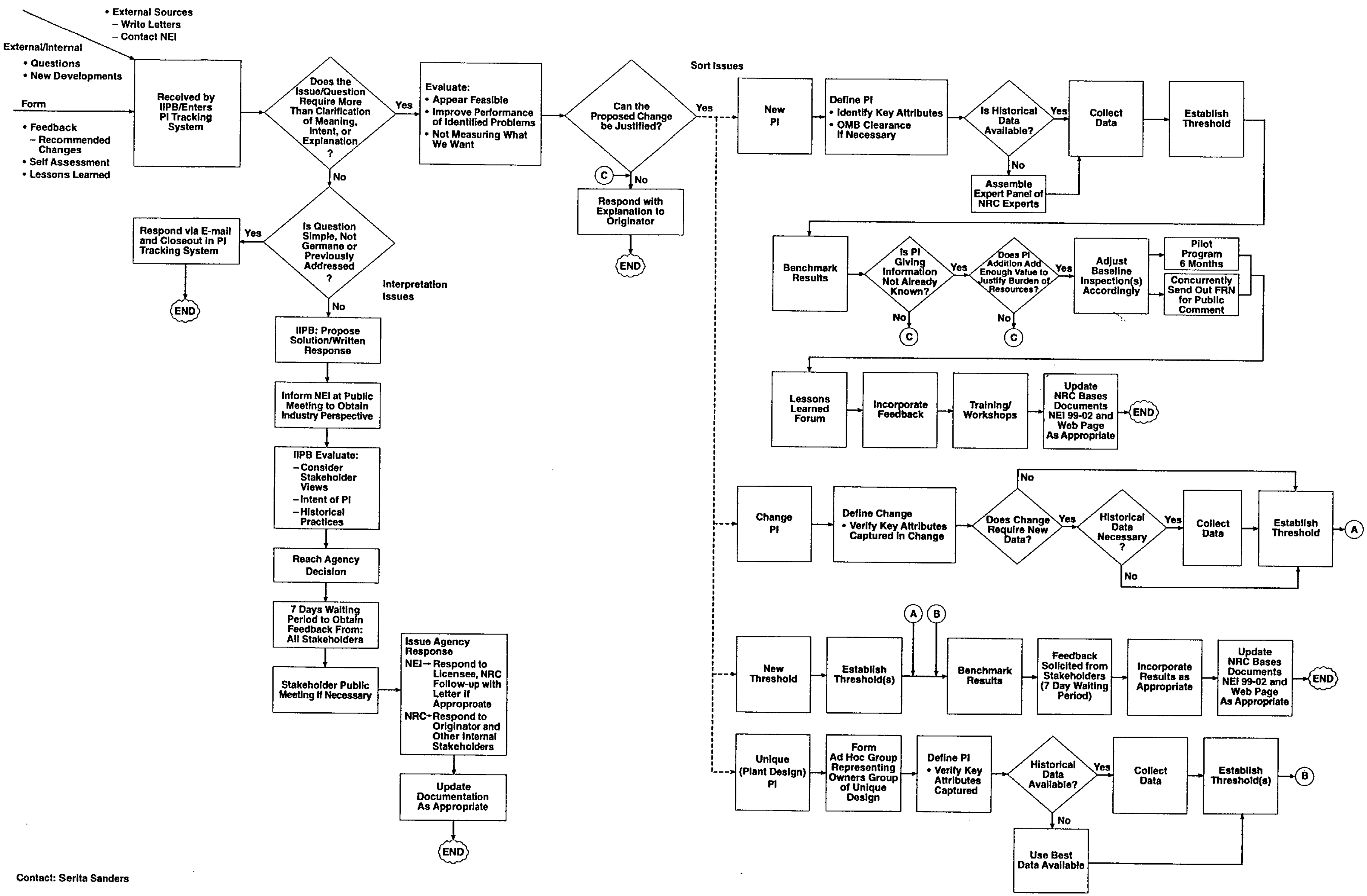
END

Exhibits:
1. Regulatory Framework
2. Reactor Oversight Process
3. Process Activities
4. Schedule of events during annual assessment cycle
5. Action Matrix
6. Plant X 4Q/1999 Performance Summary
7. Sample Assessment Follow-up Letter
8. Sample Mid-Cycle Letter
9. Sample Annual Assessment Letter For Plants in the Licensee Response Column
10. Sample Annual Assessment Letter for Plants in the Regulatory Response Column
11. Sample Annual Assessment Letter for Plants in the Degraded Cornerstone Column
12. Sample Annual Assessment Letter for Plants in the Multiple/Repetitive Degraded Cornerstone Column

# PERFORMANCE INDICATORS

## DISPOSITION QUESTIONS

## CHANGE PROCESS




Contact: Serita Sanders

Attachment 8

FAQ LOG
DRAFT
6/13/2000 4:45 PM

| FAQ LOG 7 | | | | |
|---|---|---|---|---|
| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 12. | MS01<br>MS02<br>MS03<br>MS04 | **Question:**<br>NEI 99-02 Rev 0 states on Page 33, Lines 30-32 states:<br><br>"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. Limitations on the source of the cooling water are as follows:"<br><br>Further on page 33, lines 44-47 states:<br><br>"for emergency generators, cooling water provided by a pump powered by another class lE (safety grade) power source can be substituted, provided a pump is available that will maintain electrical redundancy requirements such that a single failure cannot cause a loss of both emergency generators."<br><br>What is meant by water from another source? Does this refer to a redundant source or a diverse cooling water source? An example - for the EDG cooling water:<br><br>Is another source meant to be from a source like demineralized water or firewater or, Is a redundant Service Water or Station Auxiliaries Cooling (SACs) pump considered to be another source? | Discussed 5/24/00 | PSEG |
| | | **Response:**<br>Service Water or SACS is not considered water from another source.<br><br>A water source that is required as backup in case of equipment failure to allow the system to meet redundancy requirements or the single failure criterion is not considered to be cooling water from another source. | | |

Attachment 9

| **FAQ Log 8** | | | | |
|---|---|---|---|---|
| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 6. | IE03 | **Question:**<br>Withdrawn<br>**Response:** | Withdrawn 6/13/00 | |
| 7. | MS01 | **Question:**<br>Our site has two units, each of which has two trains of EAC with separate buses, for a total of four buses. There are four diesels on the site, and each diesel can be aligned to either unit, but are train specific. We are only required to have one diesel per train, for a total of 2 for the site, but PSA suggests that aligning each of the four diesels to its own bus is the preferred option. When one diesel is out for maintenance, we can align the other diesel in that train to both buses in the train, one bus in each unit. Technical Specifications do not limit the amount of time the plant can be in this configuration. SBO and Appendix R requirements do not impose any additional requirements on the number of diesels required per train nor do they add any additional requirements on the availability of a specific diesel unit.<br><br>We are counting unavailability for NRC indicators as follows: If an EAC bus does not have a diesel aligned to it in standby, then hours are counted for unavailability against that train. If a diesel is aligned in test to a bus, that is also counted as unavailability for that train because we cannot immediately restore the diesel nor does the diesel automatically start and supply the bus on a loss of power. If a diesel is aligned in test to both units, then it is counted as unavailability for both units. However, when a diesel is out of service for maintenance, it is not counted as unavailability if the alternate same-train diesel is aligned in standby to both buses in that train. We consider the extra diesel in each train as a maintenance train according to the rules in the NRC/NEI 99-02 guidance. Are we correct in the interpretation of these rules?<br>**Response:**<br>Based on the information provided, your interpretation of how to count diesel unavailable hours is correct. | Revised 6/13/00 | WEPCO |

FAQ LOG
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6/13/2000 4:45 PM

| FAQ Log 8 | | | | |
|---|---|---|---|---|
| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 13. | MS01 MS02 MS03 MS04 | **Question:**<br>Under "Support System Unavailability" of NEI-99-02 the statement is made that: "for monitored fluid systems with components cooled by a support system, where both the monitored and support system pumps are powered by a class 1E (i.e. safety grade or equivalent) electric power source, cooling water supplied by a pump powered by a normal (non-class 1E--i.e., non-safety-grade) electric power source may be substituted for cooling water supplied by a class 1E electric power source, provided that redundancy requirements to accommodate single failure criteria for electric power and cooling water are met. Specifically, unavailable hours must be reported when both trains of a monitored system are being cooled by water supplied by a single cooling water pump or by cooling water pumps powered by a single class 1E power (safety-grade) source". We are defining our system boundary for the reported system to include the breaker/ switchgear providing power to the reported system's pumps/valves, etc. The main switchgear/breakers are installed in the safety switchgear panels that are cooled by a common area cooling system. This cooling system is safety grade, as cooling is required following a design basis accident from a safety grade source. The cooling system has two fan coil units, using safety chilled water in each coil, a train A (&powered by train A 1E power) and a train B unit (powered by safety grade train B 1E power). Therefore cooling for the portions of the reported systems installed in the safety Switchgear panel is provided by redundant, class 1E powered, safety grade unit coolers (train A and B).<br><br>The coolers discharge to a common plenum, which in turn cools the separate switchgear rooms. Each cooler (train A and B) has 100% capacity for cooling all (train A, B, and AB) switchgear. At our site there are currently no technical specification associated with these coolers, although we have imposed a 72 hour limitation for removing one cooler (in either train) from service in our technical requirements manual (TRM), as well as a one hour shutdown action statement if both coolers (trains) are inoperable. However, since no technical specifications exist, we do not cascade inoperability or unavailability of the unit coolers into the switchgear themselves, one reason being since the cooling duct system is common to all switchgear it is impractical to cascade. In light of the above quoted statement in the NEI document, are we required to report unavailability hours in one or more trains of the reported systems, cascaded from removal of one train of the switchgear cooling system from service (i.e. removal of one of the two, redundant, fan coil units from service).<br>**Response:**<br>No. In this case, as described above, the removal of one train of area cooling would not constitute safety system unavailability if the other fan maintains environmental conditions. See NEI 99-02, page 33, lines 25 through 28. | Revised 6/13/00 | Waterford3 |

FAQ Log 8

| No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 15. | MS02 | **Question:**<br>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.<br><br>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.<br>**Response:**<br>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 can be based on reasonable and realistic assumptions regarding system and component performance including nominal pump performance and exclusive of degradation of attendant support equipment and systems. The determination of HPSI system unavailability is not subject to the same analysis requirements as the corresponding 10CFR50 Appendix K safety analysis. | On hold. NRC internal review. | APS |
| 21. | MS04 | **Question:**<br>**Appendix D Indian Point 2, Indian Point 3**<br>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.<br><br>How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR.<br>**Response:** | Set up conference call with IP2, IP3 and NRC to discuss and decide. | IP3 |

**FAQ Log 8**

| No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 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 operable and one in operation (assume no S/G's available). We consider that both SDC loops are available (SDC HX's and SDC pumps) if a Salt Water train is removed from service. Is this a proper interpretation of NEI 99-02 guidelines?<br>**Response:** Based on the information provided, this is not a proper interpretation of NEI guidance. Assuming the Salt Water System is a necessary support system, when one train of Salt Water is removed from service, you no longer meet the "Service System Unavailability" guidance of NEI 99-02 for not reporting unavailable hours. In this situation you are required to report unavailable hours for both trains of the monitored system (i.e., SDC.) | On hold. K. Borton to discuss with CC | Calvert Cliffs |
| 23. | MS04 | **Question:** At our plant, when in Mode 5, our Technical Specifications require two SDC loops to be operable with one of the SDC loops to be in operation. Infrequently, during this mode, we fill our Safety Injection Tanks (SIT) using a Containment Spray Pump. This evolution isolates the SDC pump from its SDC HX. The evolution to realign the standby SDC loop is a simple evolution and can be done promptly ( i.e. evolution can easily be accomplished well within the time frame before the standby SDC loop would be required to perform its safety function). The SDC function has no automatic start function associated with the initiation of an SDC loop. Is it necessary to station a dedicated operator during this evolution in order to avoid incurring unavailable hours for those functions that do not have an automatic start requirement?<br>**Response:** No credit may be taken for operator actions for planned or unplanned unavailable hours other than for testing as discussed on page 26 of NEI 99-02. | On hold. K. Borton to discuss with CC | 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).<br>**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 was not available and an alternate method (normally specified in the Technical Specification Action Statement) were not available. See FAQ ID 17. | Revised 6/13/00 | Duane-Arnold |

OK

FAQ Log 8

| No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 27 | MS02 | **Question:**<br>**Appendix D, Indian Point 3**<br>Regarding the HPSI indicator, we have the following question. Our plant has a unique flow path for high head recirculation. If this flow path was found isolated by a manual valve, would fault exposure hours necessarily be counted, even if the main flow path was available?<br><br>Our plant has three trains of HPSI with three intermediate pressure pumps fed by separate safety related power supplies. Our three trains share common suction supplies. For the recirculation phase of an accident, two HPSI pumps are required in the short term if the event was a small break LOCA. For a large break LOCA, the HPSI pumps are not required until we transfer to hot leg recirculation, which is required to occur between 14 and 23.4 hours after the LOCA. During high head recirculation (hot or cold leg), the HPSI suction is supplied by the output of low head pumps. We have two internal SI Recirculation pumps located in the containment that provide the primary choice for low head recirculation and for supplying the suction of the HPSI pumps. The external RHR pumps provide a backup to the internal SI Recirculation pumps for both functions. Both sets of pumps deliver flow through the RHR HXs that can then be routed to a common header for the suction of the HPSI pumps.<br><br>In the case of a passive failure requiring the isolation of the flow path to the common HPSI suction piping, we have a unique design in that a separate flow path is installed to deliver a suction supply to just one of our three SI pumps (specifically, the 32 SI pump). This flowpath bypasses the RHR HXs and would deliver sump fluid directly from the RHR pump discharge to the suction of the 32 SI pump. The internal recirculation pumps can not support this flowpath, but they can still be run for containment heat removal via recirculation spray if required. This alternate low to high head flowpath does not fit into the typical "train" design common in the industry because it is not used in the event of any active failure, and it relies on powering pumps and valves from all 3 of our EDGs. Our system is also unique in that loss of the alternate flow path is not a failure that equates to the NEI guidance. It appears that the mispositioning of a valve in the designs of the NEI guidance would cause the loss of one of two trains used for high head injection considering either and active or passive failure.<br><br>The mispositioning of the valve was reported in LER 2000-001. The LER reported a bounding risk assessment since the IPE does not model the passive failure flow path to the HHSI pumps header. The risk assessment determined that the core damage frequency (CDF) would be approximately 3E-8 per year with a conditional CDF of approximately 7.5E-9 for a period of three months (approximate time of valve misposition). This is not risk significant.<br>**Response:**<br>The fault exposure hours do not have to be counted. Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems (or sets of components) that add diversity to the mitigation or prevention of accidents. The passive failure mitigation features described as supporting the high head recirculation function, while serving a system diversity function, are not included as part of the high head safety injection system components monitored for this indicator. | Add to Appendix D | IP3 |

| FAQ Log 9 | | | | |
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| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 9.1 | EP01 | **Question**<br>This question pertains to a General Emergency Classification in which the notification of the GE Classification and the notification of the initial PAR for the General Emergency condition are integral. Should this condition count as one or two notification opportunities? | On hold. A. Nelson to address with R. Sullivan at EP workshop. | ComEd |
| 9.2 | MS01<br>MS02<br>MS03<br>MS04 | **Question**<br>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."<br><br>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? | On hold. R. Mika, W. Warren to discuss "10 minutues" with INPO. | ComEd |
| 9.3 | PP01 | **Question**<br>When rounding to the "nearest tenth" of an hour for counted "comp. hours", at what point of the data collection/computation process is the rounding applied – after an incident or at the end of each month?<br><br>**Response**<br>For this performance indicator, rounding may be performed as desired provided the reported hours are expressed to the nearest tenth of an hour. For all other performance indicators, rounding of collected data is not necessary. Data should be reported to the available accuracy. Appropriate rounding is performed during the computation of the performance indicator. | Revised 6/13/00 | ComEd |

| FAQ Log 9 | | | | |
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| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 9.4 | Gen | **Question**<br>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."<br><br>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?<br><br>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.<br>**Response**<br>The wording. "any resulting open items" means any items related to the condition causing the fault exposure. If there is no supplemental inspection, there are no open items to be closed out. | Revised 6/13/00 | Wolf Creek |
| 9.5 | IE02 | **Question**<br>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.<br><br>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).<br><br>Would this event count as a scram with loss of normal heat removal? | Question and Response revised on 6/12/00 per licensee. Action – Discuss extent of proposed response. | SCE |

| FAQ Log 9 | | | | |
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| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| | | **Licensee Proposed Response**<br>No, it would not count as a scram with loss of normal heat removal.<br><br>NEI99-02, Rev 0, page 14 and 15, define Scrams with loss of normal heat removal as "A. scrams that necessitate the use of mitigating systems and are therefore more risk-significant than uncomplicated scrams? Intentional operator actions to control the reactor cooldown rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator."<br><br>Typically, plants with steam driven main feedwater pumps run at least one feed pump after a scram because there is sufficient decay heat to support such operation. However, if an uncomplicated automatic/manual scram at low power (<30%) occurs at the beginning of an operating cycle, insufficient decay heat exists to run the main feedwater pump without causing an excess RCS cooldown. Additionally, with potential high steam generator levels, main feed operation, even with minor valve leakage, would not only worsen the high steam generator level condition but exacerbate the already impacted excess RCS cooldown. In this case, securing main feed is the prudent, safe operator action.<br><br>The metric was not intended to capture such relatively uncomplicated scrams, and it is not desired to create any disincentive to prudent operator action.<br><br>This question also clarifies the intent of NEI 99-02, Rev 0, page 15, lines 7 & 8, which uses the phrase "...Intentional operator actions to control the reactor cooldown rates... " and page 15, FAQ 4 Response, which uses the phrase "... because the system actions and operator response for this plant are normal expected actions following a scram..." Intentional operator actions which are prudent and appropriate to the circumstances to control cooldown, such as in the example above, are normal expected actions and do not count against the metric. What are "normal expected actions" and "intentional operator actions" may be based on training and may supplement procedure guidance, and "normal actions" may vary - depending upon factors such as power level and core decay heat. In the example provided, normal trip procedures may not contain explicit steps regarding trips from low power after outages due to their unlikely frequency; however, operator training, experience, and understanding of plant conditions would result in the operator intentionally securing the available main feed water to: (1) prevent an excess cooldown as well as to; (2) prevent the loss of a normal heat removal steaming path. This meets the criteria/intent of the clarifying note: "Intentional operator actions to control the reactor cooldown rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator." Therefore, this metric focuses on whether the scrams necessitated the use of mitigating systems, and is not focused on procedural adequacy nor verbatim procedural compliance (which are addressed in the inspection, significance determination, and enforcement processes). | | |

| FAQ Log 9 | | | | |
|---|---|---|---|---|
| No. | PI | Question/Response | Status | Plant/ Co. |
| 9.6 | EP01 | **Question**<br>For sites with multiple agencies to notify, are notifications considered to be initiated when the first agency is contacted or when the last agency is contacted?<br><br>The site makes notification to 6 offsite agencies, usually simultaneously using a dedicated telephone line. About 95% of the time, we are able to get all 6 agencies on the line at one time. However, there have been a few cases when we haven't achieved this goal. With six different agencies to contact, there are many things that could go wrong that would prevent getting all of the agencies at one time. For example, the offsite agencies are aware of our announced drills in advance. As a result, they will sometimes not answer their phone right away if there are a number of real emergencies occurring at that time. Also, there have been instances when an excavator inadvertently cut the telephone line, and finally there have been a few equipment failures. There is a thorough backup process in place to deal with these problems and still ensure timely notifications. Furthermore, the dedicated line is tested monthly to ensure its reliability. Hence, most of the time, the process works as intended. Our question arises for the situation when it doesn't. In such a case, we are must do sequential calls.<br><br>When calling sequentially, it will clearly take longer for a site that has 6 agencies to initiate contact with the 6th agency than it will take for a site that has only 1 agency. It is our understanding that one of the objectives of the performance indicators is to be able to differentiate the performance between the various sites. However, there cannot be a true comparison if one site has 6 agencies to notify and another site only has one. In order to truly compare "apples with apples", a site that 1 agency to notify and a site that has 6 agencies to notify should have an equal chance to both succeed and fail. Therefore, the criteria should be clarified to indicate that notifications should be considered timely if verbal contact made to the first agency within 15 minutes of event declaration. | On hold. A. Nelson to address with R. Sullivan at EP workshop. | Amergen |
| 9.7 | EP01 | **Question**<br>For expansion of the Protective Action Recommendation (PAR), does the 15 minute assessment period start as soon as any dose projection is received indicating that the PAR might need to be expanded, or when there is sufficient data to determine that the PAR needs to be expanded?<br><br>If the need to expand the PAR was based strictly on a wind shift resulting in more sectors that need to be evacuated, then 15 minutes to determine the new PAR seems quite reasonable. However, there are other times when the responders may receive a dose projection code output indicating that doses may exceed EPA Protective Action Guidelines outside the initial recommended evacuation area. If the responders act solely on the information provided by that dose projection before they have had a chance to verify its accuracy, they could expand the PAR when it was not truly warranted. NUREG 0654 Supplement 3 states, "After performing the initial early evacuation actions near the plant, licensee and offsite officials should continue assessing the situation, including the development of dose projections and performing field monitoring. These assessments should be used to determine if the protective actions should be expanded with field monitoring data being the preferred basis on which to determine if people should be relocated from sheltered areas." NUREG 0654 guidance seems to suggest that the 15 minutes used for assessment should not start until field monitoring data is available to verify the accuracy of the dose protection produced through a computer code. Waiting for field monitoring results before expanding the PAR seems reasonable since actions have already been taken to protect those most at risk through implementation of the initial PAR. | On hold. A. Nelson to address with R. Sullivan at EP workshop. | Amergen |

| FAQ Log 9 | | | | |
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| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 9.8 | EP01 | **Question**<br>At what point in time should it be considered that there are "indications are available to control room operators that an EAL (Emergency Action Level) has been exceeded"?<br><br>We recommend clarifying this start time to that point in time when the operators have sufficient data available to them to enable them to determine that an EAL has been exceeded.<br><br>For most events, the point in time when the operators have sufficient data available to them to determine that an EAL has been exceeded matches up with when the first indications of a problem are received. However, there are scenarios when those two points in time don't match up. As an example, at TMI an Unusual Event must be declared if we are steaming directly to atmosphere and we have a primary to secondary leak greater than 1 gallon per minute (gpm). The operators might know quite quickly that there is a primary to secondary leak. However, if that leak is not very large, determining whether the leak is greater than 1 gpm could take longer than 15 minutes, particularly if the plant is just starting up. In fact, a number of years ago, TMI did have a primary to secondary leak of just over 1 gpm during start up. It took nearly 24 hours before the plant could accurately determine the leak rate because the operators conservatively shut the plant down as soon as they had any indication of a leak. The resulting transient condition made it extremely difficult to calculate the leak rate due to changing radiological conditions and changing mass balance conditions. | On hold. A. Nelson to address with R. Sullivan at EP workshop. | Amergen |
| 9.9 | MS01<br>MS02<br>MS03<br>MS04 | **Question**<br>Our station has several areas containing a variety of safety system components from multiple safety systems and both trains (motor operated valves, instrumentation, pumps, etc.). Examples are the auxiliary building general area, pipe chases, penetration rooms, etc. These general areas are cooled by what we refer to as "area coolers" and there is an A train and a B train cooler for each area, both fed from opposite divisions of class 1E power and separate trains of cooling water. Additionally, these fans have 100% capacity (each) to maintain the required temperature for the area; i.e., these could be viewed as installed spares. As far as support systems to the fan, with one train of area cooling out of service, it would require a loss of 2 off-site power supplies coincident with the specific train of diesel generator power and cooling to render the remaining train of area cooling unavailable.<br><br>Based on the guidelines given in NEI 99-02, R0, section 2.2, *"Support System Unavailability"*, we interpret this to mean that if we remove one train of area cooling, it would <u>not</u> constitute any safety system unavailability.<br><br>Is this a correct interpretation?<br>**Response**<br>Yes. In this case, as described above, the removal of one train of area cooling would not constitute safety system unavailability if the other fan maintains environmental conditions. See NEI 99-02, page 33, lines 25 through 28. | Response Revised 6/13/00 | TVA |

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|---|---|---|---|---|
| **No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 9.10 | MS01<br>MS02<br>MS03<br>MS04 | **Question**<br>SSES has 5 diesel generators, 4 are required to support operation of both units and the fifth is an installed spare capable of substituting for any one of the other 4. We perform diesel generator overhauls with the units on line by swapping in the spare for the overhauled diesel to maintain the required number of 4. No unavailable time is charged during the overhaul. However, following the overhaul we perform post maintenance testing and are in a 72-hour LCO until the overhauled diesel is declared operable. We have previously counted this post maintenance testing time as unavailable.<br><br>In light of the new FAQ's approved on 5/24...particularly as FAQ 178 on Planned Overhaul hours would apply to our unique design...is it the intent of this PI to include the post maintenance testing time following a planned overhaul as unavailable hours? If it is not required to be included and we revise previously submitted data, how far back can we go to make the revision?<br><br>**Response**<br>The site should not count post maintenance testing of a Diesel Generator following overhaul as unavailable time. Since the scheduled maintenance window includes the necessary post maintenance testing time you are not required to count that time as unavailable. | Added 6-1-00 | Susquehanna |

DRAFT

**Question**

Does the response to FAQ #88 mean that engineering judgment is equivalent to and can be used in lieu of component failure analysis, circuit analysis, or event investigation?

**Proposed Response**

The intent of the use of the term "with certainty" is to ensure that an appropriate analysis and review to determine the time of failure is completed, documented in your corrective action program, and reviewed by management. The use of component failure analysis, circuit analysis, or event investigations are acceptable. Engineering judgment may be used in conjunction with analytical techniques to determine the time of failure.

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**Question**

With reference to the answer to FAQ #4, a normal, expected operator action following a scram is to avoid an excessive cooldown rate by taking appropriate action, such as securing main feedwater or closing the MSIVs. Is this what is intended by the phrase "intentional operator actions to control the reactor cooldown rate ..... are not counted in this indicator?"

**Proposed Response**

The exclusion for operator actions to control the cooldown rate only applies to actions taken by an operator in accordance with his/her training and procedures or other documented direction from management as the preferred method for operating the plant, and that are followed after every reactor scram. Intentional operator actions to control the reactor cooldown rate that are necessary in particular situations due to off-normal conditions, and that result in the use of alternate means of decay heat removal, are included in the indicator.

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**Question**

**Appendix D North Anna and Surry**

At North Anna Power Station we have only one part time CCTV camera that is used as part of the PA perimeter threat assessment during refueling outages. At Surry Power Station we have only one full time CCTV camera that is used as part of the PA perimeter threat assessment. With one part time or one full time CCTV camera that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with such a low number of CCTV cameras?

**Response**

Continue to report compensatory hours for both the Intrusion Detection and the Closed Circuit Television systems. However, it is not appropriate to average the two to determine the Security Equipment Performance Index. The index will be calcuclated using only the IDS compensatory hours.

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**Question**

Is it necessary to perform a risk assessment to show that a 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

Attachment 10

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. 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 unavailable hours must be counted.

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**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 shutdowns? 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.

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**Question**

The definition of the RCS Specific Activity PI is the maximum monthly 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 limit, whether it is in technical specifications, a license condition, or is an administrative limit.

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**Question**

For the unplanned power changes PI, how is a 20% power change to be determined?

**Response**

A power change for this indicator should be determined by the nuclear instruments.

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## FAQ 15

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.

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**Question:**
A post survey was not completed until approximately 4 hours after a sluicing evolution was completed, which revealed exposure levels between 1000 and 1100 millirem per hour at 30 centimeter from the spent resin liner, representing a locked high radiation area as defined by the licensee procedures. Although the survey results were documented, the entrance to the pit remained unguarded and unlocked for approximately an additional 20 hours before the access to the area was secured. Are these concurrent occurrences or two separate occurrences?

**Response:**
These are two separate occurrences. Timeliness of securing the high radiation area was the determining factor in this being two separate occurrences. Once the area was surveyed, and the licensee recognized that the area needed to be controlled per TS, the licensee had a second program failure in that they did not provide those controls for an additional 20 hours. This second failure does not meet the intent of "concurrent non-conformances" in the PI definition and is a second, separate, PI hit.

DRAFT