Unscheduled Shutdowns

UNSCHEDULED REACTOR SHUTDOWNS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of reactor shutdowns per year of critical operation. Because the contribution to plant risk of unscheduled reactor shutdowns varies considerably, it is not possible to assign a risk significance to this indicator. It is believed to provide leading indication of risk-significant initiating event frequency.

Indicator Definition

The number of unscheduled reactor shutdowns per 7,000 critical hours during the previous four quarters.

Data Reporting Elements

Report the following data for each reactor unit each quarter:

- the number of unscheduled reactor shutdowns in the previous quarter
- the number of critical hours in the previous quarter

Calculation

$$\text{value} = \frac{\text{(unscheduled reactor shutdowns in the previous four quarters) X 7,000 hrs}}{\text{(number of hours critical in the previous four quarters)}}$$

Definition of Terms

Reactor shutdown occurs when a critical reactor is taken subcritical by any means.

Unscheduled, for purposes of this indicator, is a reactor shutdown that was not scheduled prior to startup for the current fuel cycle.

Clarifying Notes

7,000 critical hours represent one year of reactor operation with an 80.0% availability factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

Attachment 3

10 CFR 50.72 REPORTABLE UNSCHEDULED REACTOR SHUTDOWNS

Purpose
This indicator monitors the number of reactor shutdowns per year of critical operation that are reportable per 10 CFR 50.72(b)(2)(iv)(B). It is a subset of Unscheduled Reactor Shutdowns. Thresholds are set assuming these events are uncomplicated by equipment or human failures.

Indicator Definition
The number of unscheduled reactor shutdowns reportable per 10 CFR 50.72(b)(2)(iv)(B) per 7,000 critical hours during the previous four quarters.

Data Reporting Elements
Report the following data for each reactor unit each quarter:

- the number of unscheduled reactor shutdowns reportable per 10 CFR 50.72(b)(2)(iv)(B) in the previous quarter
- the number of critical hours in the previous quarter

Calculation

$$\text{value} = \frac{\text{(reportable reactor shutdowns in the previous four quarters) X 7,000 hrs}}{\text{(number of hours critical in the previous four quarters)}}$$

Definition of Terms
Reactor shutdown occurs when a critical reactor is taken subcritical by any means.

Unscheduled, for purposes of this indicator, is a reactor shutdown that was not scheduled prior to startup for the current fuel cycle.

Clarifying Notes
7,000 critical hours represent one year of reactor operation with an 80.0% availability factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

10 CFR 50.72(b)(2)(iv)(B) requires reporting of "any event or condition that results in actuation of the reactor protection system (RPS) when the reactor is critical except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation."

10 CFR 50.72 REPORTABLE UNSCHEDULED REACTOR SHUTDOWNS WITH LOSS OF NORMAL HEAT REMOVAL

Purpose

This indicator monitors the number of reactor shutdowns per year of critical operation that are reportable per 10 CFR 50.72(b)(2)(iv)(B) and that involve the loss of the normal heat removal path through the main condenser. It is that subset of 10 CFR 50.72 Reportable Unscheduled Reactor Shutdowns that are either initiated or complicated by the loss of the normal heat removal path through the main condenser. Such occurrences are more risk significant than uncomplicated reportable reactor shutdowns.

Indicator Definition

The number of unscheduled reactor shutdowns reportable per 10 CFR 50.72(b)(2)(iv)(B) that involve the loss of the normal heat removal (LONHR) path through the main condenser per 7,000 critical hours during the previous four quarters.

Data Reporting Elements

Report the following data for each reactor unit each quarter:

- the number of unscheduled reactor shutdowns reportable per 10 CFR 50.72(b)(2)(iv)(B) that involve the loss of the normal heat removal path through the main condenser in the previous quarter

- the number of critical hours in the previous quarter

Calculation

$$\text{value} = \frac{\text{(reportable reactor shutdowns w/ LONHR in the previous four quarters) X 7,000 hrs}}{\text{(number of hours critical in the previous four quarters)}}$$

Definition of Terms

Reactor actuation occurs when a critical reactor is taken subcritical by any means.

Unscheduled, for purposes of this indicator, is a reactor actuation that was not scheduled prior to startup for the current fuel cycle.

The normal heat removal path through the main condenser, for purposes of this indicator, comprises the following:

- main feedwater
- main steam isolation valves (MSIVs)
- turbine bypass valves
- condenser

Loss of the normal heat removal path means that an RPS actuation has occurred either due to loss of all main feedwater flow or to a decrease in condenser vacuum, or that there has been some abnormal occurrence, such as equipment failure or operator error, that causes any of the following conditions to occur and prevents easy recoverable from the control room without the need for diagnosis or repair:

- complete loss of all main feedwater flow
- complete closure of at least one MSIV in each main steam line
- failure of turbine bypass valve capacity that results in insufficient bypass capacity remaining to maintain reactor pressure and temperature
- decrease in condenser vacuum

Clarifying Notes

7,000 critical hours represent one year of reactor operation with an 80.0% availability factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

10 CFR 50.72(b)(2)(iv)(B) requires reporting of "any event or condition that results in actuation of the reactor protection system (RPS) when the reactor is critical except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation."

Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on an RPS actuation, are not counted as long as the normal heat removal path is easily recoverable from the control room without the need for diagnosis or repair.

Intentional operator actions to control the reactor cooldown rate, such as securing main feedwater, are not counted as long as the normal heat removal path is easily recoverable from the control room without the need for diagnosis or repair.

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

NEI Draft

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:

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

RAPID REACTOR SHUTDOWNS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of rapid shutdowns of the reactor in response to adverse plant conditions. It measures the frequency of rapid shutdowns per 7,000 critical hours and provides an indication of initiating event frequency.

Indicator Definition

The number of occurrences of rapid shutdown of the reactor in response to adverse plant conditions 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 rapid shutdowns of the reactor in response to adverse plant conditions while critical in the previous quarter

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

Attachment 4

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 shutdown means the shutdown of the reactor in response to adverse plant conditions by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, or opening reactor trip breakers. Rapid shutdowns are those that bring the reactor from criticality to a shutdown state within 15 minutes.

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 rapid shutdown.

Clarifying Notes

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

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

Examples of adverse plant conditions include:

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
Rapid shutdowns made in response to plant conditions in accordance with off-normal procedures (e.g., emergency procedures, abnormal operating procedures, and alarm response procedures)

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 evolution made in accordance with normal plant procedures.

Frequently Asked Questions

ID Question
The Clarifying Notes for the conditions requiring rapid shutdown per 7000hrs PI states that "rapid shutdowns that are part of a normal planned operation or evolution" are not counted. If a licensee enters an LCO requiring the plant to be in Mode 2 within 7 hours, applies a standing operational procedure for assuring the LCO is met, and a manual scram is executed in accordance with that procedure, is this event counted as a rapid shutdown?

Response
If the plant shutdown to comply with the Technical Specification LCO, was conducted in accordance with the normal plant shutdown procedure, which includes a manual scram to complete the shutdown, the scram would not be counted as a rapid shutdown. However, the power reduction would be counted as a condition requiring a significant power change (assuming the shutdown resulted in a power change greater than 20%). However, if the actions to meet the Technical Specification LCO required a manual rapid shutdown outside of the normal plant shutdown procedure, then the scram would be counted as a rapid shutdown.

ID Question
With the Unit in Operational Condition 2 (Startup) a shutdown was ordered due to an insufficient number of operable Intermediate Range Monitors (IRM). The reactor was critical at 0% power. "B" and "D" IRM detectors failed, and a plant shutdown was ordered. A manual scram was inserted in accordance with the normal shutdown procedure. Should this count as a rapid reactor shutdown?

Response
No. If part of a normal shutdown, (plant was following normal shut down procedure) the rapid reactor shutdown would not count.

RAPID REACTOR SHUTDOWNS WITH A LOSS OF NORMAL HEAT REMOVAL

Purpose

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

Indicator Definition

The number of rapid reactor shutdowns 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 rapid reactor shutdowns 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 shutdown means the shutdown of the reactor in response to adverse plant conditions by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, or opening reactor trip breakers. Rapid shutdowns are those that bring the reactor from criticality to a shutdown state within 15 minutes.

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 rapid shutdown.

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 consists of rapid shutdowns in which the normal heat removal path through the main condenser was lost. This indicator is also counted for the Rapid Reactor Shutdowns per 7,000 Critical Hour 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

ID Question
The NEI 99-02 instructions for Conditions Requiring Rapid Reactor Shutdowns with a Loss Of Normal Heat Removal (LONHR) equate LONHR with "loss of main feedwater." At some plants the feedwater pumps trip on high reactor water level, which normally occurs on most rapid shutdowns. To prevent the feedwater pumps from tripping during a rapid shutdown, the operator has to quickly take manual control of level. Since the operators often have more important concerns during a rapid shutdown (e.g., trying to figure out what happened, verifying all the rods are in, etc.) they have been instructed (correctly) to let the pumps trip. When this occurs steam continues to flow to the condenser and make up to the reactor is accomplished using other means (e.g., CRD pumps). Does this count against the LONHR indicator?

Response
In this instance, because the system actions and operator response for this plant are normal expected actions following a rapid shutdown, this would not count against the LONHR indicator.

ID Question
Does the Conditions Requiring Rapid Reactor Shutdowns with a Loss Of Normal Heat Removal PI include main condenser perturbations that result in rapid shutdown. For example, if a scram occurs due to a partial or total loss of main feedwater and then, as expected, main feedwater is isolated as part of the plant design following the scram, does this count as a Condition Requiring Rapid Reactor Shutdown with a Loss of Normal Heat Removal. Similarly, do rapid shutdowns that occur due to a partial loss of condenser vacuum affect this PI.
Response
The PI is monitoring the use of alternate means of decay heat removal following a rapid shutdown. Therefore, the described feedwater scenario would not be included in the PI. Similarly, a partial loss of condenser vacuum that results in a rapid shutdown yet provides adequate decay heat removal following the rapid shutdown would not be included in the PI.

ID Question
Under the "Condition Requiring Rapid Reactor Shutdown with Loss of Normal Heat Removal" performance indicator in NEI 99-02, the Definition of Terms states that a "loss of normal heat removal path" has occurred whenever any of the following conditions occur:

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

The purpose of the indicator is to count rapid shutdowns that require the use of mitigating systems, however, instances that meet the above criteria in a literal sense could occur without the necessity of using mitigating systems. For example, a short term loss of main feedwater injection capability due to pump trip on high reactor water level post-scram is a common BWR event. Under these conditions, there is ample time to restart the main feed pumps before addition of water to the vessel via HPCI or RCIC is required. A second example would be a case where the turbine bypass valves (also commonly called steam dump valves) themselves are unavailable, but sufficient steam flow path to the main condenser exists via alternate paths (such as steam line drains, feed pump turbine exhausts, etc.) such that no mitigating systems are called upon.
Response
If an alternate heat removal system is put into use, it counts toward the performance indicator

Question (FAQ Log 9, Temp. No. 9.1)
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?

Response
Two. As is discussed in Question ID 29 on page 93 of NEI 99-02, notification of the PAR and notification of the GE Classification are separate opportunities, individually subject to the timeliness and accuracy criteria.

Question (FAQ Log 9, Temp. No. 9.6)
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?

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.

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 is made to the first agency within 15 minutes of event declaration.

Response
The notification is considered to be initiated when the first agency is contacted. As noted on page 91 of NEI 99-02 in the definition of timely, the offsite notifications are to be initiated (verbal contact) within 15 minutes of classification or PAR development. It should be noted that in many drill situations, the verbal contact may be with a controller rather than the actual offsite agency, or the contact with offsite agencies may be simulated in a manner that otherwise reasonably simulates the interaction.

Attachment 5

Question (FAQ Log 9, Temp. No. 9.7)
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?

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.

Response
A conservative approach should be utilized in recognizing the need for PAR expansion. PARs are developed within 15 minutes of data availability. Plant conditions, meteorological data and/or radiation monitor readings should provide sufficient information to determine the need to change PARs. While field monitoring data can be useful, it is not appropriate to wait for that data to become available if other data demonstrate the need to expand the PAR.

Question (FAQ Log 9, Temp. No. 9.8)
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"?

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.

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.

Response
The NEI/industry consensus was that this FAQ should be dropped. Sufficient guidance is available in 99-02 on page 92.

Question (from NRC PI Feedback Interpretation Form)
Regarding taking credit for notification performance opportunities, NEI 99-02, page 91 defines opportunities for notifications as those made to the state and/or local government authorities. The guidance further defines timely as those offsite notifications that are initiated must be verbal in nature. On page 92 under clarifying notes (second paragraph), NEI 99-02 states that notifications may be included in the PI if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. This particular note applies to operating shift simulator evaluations, not emergency drills.

Can credit can be taken for the notification performance opportunity when notifications are simulated during emergency drills (i.e., not operator simulator evaluations), with no actual verbal contact, as long as the procedures are completed up to the time the notification is made.?

Response
99-02 allows for the simulation of notification of offsite agencies in the case of simulator based drills. There is no reason not to allow the same simulation for other EP drills. However, since the guidance in NEI 99-02 seems specific to simulator drills, it has been interpreted as not allowing such simulation for other drills. The guidance will be clarified in a future revision of the document.

It is not expected that State/local agencies be available to support all drills conducted by licensees. The drill should reasonably simulate the contact and the participants should demonstrate their ability to use the equipment. Generally, the contact is simulated through the use of a controller answering a phone. Although this method will not test the equipment, communications tests are required by Appendix E to 10 CFR 50 and the Emergency Plan should delineate such tests.

Question (from NRC PI Feedback Interpretation Form)
RG&E recently had a regularly scheduled silent siren test failure. Immediately following the test failure, a request to test the sirens from an alternate location (the local county has 74 sirens that can be activated from either one of two locations) was performed and it failed as well. My question is how many tests should be counted in the PI? My read on the guidance leads me to believe that only the first set of failures should be counted since that was the "regularly scheduled" test. The second test was somewhat of a troubleshooting test. There is some confusion among the licensee's staff as to how many tests should count. Some people also

think that the post maintenance tests should be counted. I don't think that this indicator should be treated like the EP drill and exercise performance PI (i.e., if the PI is low, a licensee can do more drills to bring up the PI). Counting more successful siren tests (either post maintenance or troubleshooting) would mask the true reliability of the siren system that's being measured during the regularly scheduled tests.

Response
One. The failure of the first system should be a failure and the backup system should not be an additional failure, nor should it be counted as a success if it were successful. The purpose of the PI is to give an indication of the manner in which the licensee maintains important EP equipment. This being the case, it is not appropriate to count the back up system success rate.

The test should not be 2 failures (by the way since all the sirens failed, we are talking about 1 or 2 times the # of sirens as the number of failures).

Site procedures for activation of the siren system vary. Some procedures may include use of the back up system should the main system fail.

NRC-DRAFT

Question
Temp. FAQ No. 9.5, SONGS scram w/LONHR

Proposed Response
No. The scrams with loss of normal heat removal indicator captures events in which the normal heat removal path is not available and there has been some abnormal occurrence(s), such as equipment failure or operator error, that prevents easy recover of the path from the control room. Design features or operator actions to control the reactor cooldown rate do not count, as long as the normal path through the main condenser is easily recoverable from the control room without the need for diagnosis or repair. The indicator also counts scrams caused by the complete loss of all main feedwater flow and a decrease in condenser vacuum.

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 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~~ Numarc 93-01 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.

IIPB's Proposed Response to FAQ Temp. No. 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.

Question
Temp. FAQ No. 9.10, SSES EDG testing

Proposed Response

If the spare diesel has been removed from service to allow testing of the recently overhauled diesel, then unavailable hours would only be counted if the diesel fails the post-maintenance test. The diesel could be considered available prior to the test, however, if the test is unsuccessful, those hours would have to be changed to unavailable hours.

Question

On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as "The ability of the monitored system to take suction from the condensate storage tank **or** [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel." However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI?

Response

Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of both paths. The guidance in NEI 99-02 will be changed from *or* to *and*.

Question

Temp. FAQ No. 10.2 - Withdrawn

Question

A post survey was not completed until approximately four hours after a resin sluicing evolution was completed, which produced dose rates greater than 1000 mrem per hour at 30 cm from the spent resin liner. The licensee's Technical Specifications require such an area to be controlled as a locked high radiation area. Once performed the radiation survey indicated that the dose rates exceeded those allowed by Technical Specifications. However, the area remained unguarded and unlocked for an additional 20 hours before it was controlled in accordance with the Technical Specifications. Do these events constitute "concurrent nonconformances" as used in the Performance Indicator definition, and therefore, one PI occurrence?

Response

No. The definitions for both the *Technical Specification High Radiation Area Occurrence* and the *Very High Radiation Area Occurrence* start out "A nonconformance (or concurrent nonconformances) with.."[Technical Specifications, or 10 CFR 20, respectively]. As used in these definitions, *concurrent* means "existing at the same time and resulting from the same cause." During the first four hours of this example, the failure to perform a timely radiation survey was the cause of the failure to post the area, control access to the area, and provide dosimetry as required by Technical Specifications. They are therefore concurrent nonconformances and constitute a single PI count. However, after the survey was performed, the failure to establish proper controls over access to the area in a timely manner was caused by another programmatic breakdown that could not be considered the same as or concurrent with

the failure to perform the survey. This is an example of a *sequential* failure that warrants a second PI count.

Question
Temp FAQ No. 10.7

Response
Licensees should use the most restrictive regulatory limit (e.g., technical specifications or license condition). However, if an administrative limit is in place due to uncertainty about compliance with 10 CFR Part 100 using the regulatory limits, licensees should use the highest administrative limit that ensures compliance with 10 CFR Part 100.

Question
Temp FAQ No. 9.2

Response
Yes. All references to time constraints were intended to be removed from NEI 99-02. In addition, any reference to allowance for actions to recover from a failure was also intended to be removed. Due to an oversight the words on page 29, line 5, were not removed. This will be corrected in the next revision of the document.

Question
Regarding the Unplanned power change PI, I have the following questions:

1. Is the 20% full power intended to be 20% of 100%power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97) = 19%].
2. If an unplanned transient occurs which is greater than 20%, the operators stabilize the plant briefly and then without any forethought cause a transient greater than 20% in the opposite direction, does that count as 2 hits against the PI?
3. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?

Response

1. It is intended to be 20% of 100% power.
2. Yes.
3. Licensees should use the most reliable indication of power.

FAQ Log 8				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
7.	MS01	**Question:** 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. 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? **Response:** Based on the information provided, your interpretation of how to count diesel unavailable hours is correct. This configuration would be reported as a two-train system.	Revised 6/13/00 Discussed 6/14/00 Revised 6/14/00. Action: Discuss revised words with WEPCO 7/11/00 – WEPCO agrees Approved 7/12/00	WEPCO
15.	MS02	**Question:** Our HPSI system is similar to that depicted in Figure 5.2 of NEI 99-02, consisting of two independent trains, as defined NEI 99-02 for monitoring purposes. Each train consists of one HPSI pump and the associated train related valves and piping. Each pump is able to take a suction from the Refueling Water Tank (RWT) or Containment Sump (CS), and inject into the RCS through four cold leg injection flow paths and one hot leg flow path. Each cold leg flow path includes one motor operated isolation valve and an isolation check valve. These flow paths, four each for the two independent trains, then converge into four common headers that flow to the RCS. Flow may be split between the train related cold legs and the associated hot leg later into an event when necessary to preclude boron precipitation in the core. We are performing an analysis to demonstrate that injection flow, sufficient to satisfy the requirements of the safety analysis, can be achieved by either train with one of its four cold leg injection paths out of service. Is it acceptable, in the assessment of NEI 99-02 availability, to employ realistic component performance assumptions in a system level analysis, or is the utility required to use all design basis assumptions, consistent with those used in the associated safety analysis. **Response:** Fault exposure unavailable hours are not counted for a failure to meet design or technical specifications, if engineering analysis determines the train was capable of performing its safety function during an operational event. The engineering analysis must take into account other equipment deficiencies that existed at any time during the failure to meet design or technical specification requirements, and must assume the worst case accident for the plant conditions. However, it is not necessary to assume an independent single failure and the analysis can assume nominal (expected) performance of other plant equipment. System unavailability is not subject to the same analysis requirements as the corresponding 10CFR50 Appendix K safety analysis.	Discussed 6/14/00 Revised 6/14/00 Action: NEI discuss revised response with APS 7/11/00 – awaiting response from APS 7/12/00 – Discussed, on hold	APS

Attachment 6

FAQ Log 8				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
21.	MS04	**Question:** **Appendix D Indian Point 2, Indian Point 3** The ECCS designs for Indian Point 2 and Indian Point 3 include two recirculation pumps, recirculation containment sump, piping and associated valves located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to RHR), two RHR heat exchangers and associated valves. These two subsystems are identified in the Technical Specifications and FSAR. The RHR/LHSI system is automatically started on an SI, takes suction from the RWST as does the high head SI pumps (3), and provides water in the injection phase of an accident. The recirculation pumps are in standby in the injection phase and are actuated by operator action during switchover for the recirculation phase of an accident and RHR is put in standby. The recirculation pumps (2) take suction from its dedicated sump and have the capability to feed the containment spray system, low head injection lines and the suction of the high head SI pumps for high head injection. The recirculation pumps are inside containment and can not be tested during operation, but both are required to be operable above 350 degrees F and one above cold shutdown. How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR.	Set up conference call with IP2, IP3 and NRC to discuss and decide.	IP3
		Response:		
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?	On hold. K. Borton to discuss with CC	Calvert Cliffs
		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.)		
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?	On hold. K. Borton to discuss with CC 7/11/00 – Withdrawn per request of Calvert Cliffs 7/12/00 – Withdrawn	Calvert Cliffs
		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.		

FAQ Log 8

Temp No.	PI	Question/Response	Status	Plant/ Co.
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). **Response:** Yes. Unavailable hours are counted only for periods when a train is required to be available for service. However, Technical Specifications that require one subsystem remain operable and in operation above a specified temperature would be counted if one subsystem were not available or an alternate method (normally specified in the Technical Specification Action Statement) were not available. See FAQ ID 17.	Revised 6/13/00 Discussed 6/14/00 Action: NRC to discuss with Residents	Duane-Arnold

FAQ Log 9				
Temp. No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
9.1	EP01	**Question** 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? **Response** Two. As is discussed in Question ID 29 on page 93 of NEI 99-02, notification of the PAR and notification of the GE Classification are separate opportunities, individually subject to the timeliness and accuracy criteria.	Response developed and discussed at EP workshop. 7/11/00 – alternate response proposed by NRC Approved 7/12/00	ComEd
9.2	MS01 MS02 MS03 MS04	**Question** NEI 99-02 Revision 0 defines criteria for determining availability during surveillance testing. This definition can be found on page 26. It allows operator action to be credited for the declaration of availability. NEI 99-02 also defines criteria for determining fault exposure. This definition can be found on pages 28 & 29. Line 5, page 29 references operator action. It states, "Malfunctions or operating errors that do not prevent a train from being restored to normal operation within 10 minutes, from the control room, and that do not require corrective maintenance, or a significant problem diagnosis, are not counted as failures." In addition, page 29, line 13, states, "A train is available if it is capable of performing its safety function." If the fault can be corrected quickly (much less than 10 minutes) by a single operator action that is contained in a written procedure, is uncomplicated, and does not require diagnosis or repair, but the operator action cannot be shown to satisfy auto-start time design assumptions (e.g., HPCI injection within 45 seconds), should fault exposure hours be assigned to a failure? **Response**	. 7/12/00 – NRC action to confirm consistency with MR and expand upon response.	ComEd
9.5	IE02	**Question** During a startup following a refueling outage (reactor at 24% power w/minimal decay heat), one feed water regulating valve failed open causing a loss of feed water control. In response, one of the two feed water pumps was manually tripped to minimize overfeeding of the steam generators. SG levels continued to rise, so the reactor was manually scrammed. Within one minute of scram, with normal heat removal still available through both main feedwater bypasses, the failed open feed water regulating valve was isolated by closing it's feed water block valve as part of Standard Post Trip Actions. Operators quickly diagnosed this as an uncomplicated reactor trip and completed the remaining steps of Standard Post Trip Actions. Eleven minutes after the scram with steam generator levels continuing to slowly rise, the remaining feed water pump was stopped to terminate overfeeding of the steam generators and avoid excess RCS cooldown. Nineteen minutes after the scram, the Reactor Trip Recovery procedure was entered. Thirty nine minutes after the scram, with steam generator levels down to normal levels, AFW was established at 81 gpm for normal startup feed water alignment. Three minutes later, the Plant Startup procedure was initiated. Mitigating systems such as Aux feed and Atmospheric Dump valves were not required nor used to establish scram recovery conditions. Rather, steam generator inventory provided by normal feed water and the normal steam path to main condenser via the normal steam bypass control system accounted for 100% capability for post scram RCS heat removal (i.e., no loss of capability for performing the heat removal function). Would this event count as a scram with loss of normal heat removal?	Discussed 6/14/00 On-hold, NRC review ongoing. 7/12/00 – Response revised and approved.	SCE

FAQ Log 9				
Temp. No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
		Response No.		
9.6	EP01	**Question** 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? 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. 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. This question arises for the situation when it doesn't. In such a case, we do sequential calls. 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. The criteria should be clarified to indicate that notifications should be considered timely if verbal contact is made to the first agency within 15 minutes of event declaration.	Question revised and Response developed at EP workshop. Approved 7/12/00	Amergen
		Response The notification is considered to be initiated when the first agency is contacted. As noted on page 91 of NEI 99-02 in the definition of timely, the offsite notifications are to be initiated (verbal contact) within 15 minutes of classification or PAR development. It should be noted that in many drill situations, the verbal contact may be with a controller rather than the actual offsite agency, or the contact with offsite agencies may be simulated in a manner that otherwise reasonably simulates the interaction.		
9.7	EP01	**Question** 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 field data to confirm that the PAR needs to be expanded? (change back to original question)	Response developed at EP workshop. Approved 7/12/00	Amergen
		Response A conservative approach should be utilized in recognizing the need for PAR expansion. PARs are developed within 15 minutes of data availability. Plant conditions, meteorological data and/or radiation monitor readings should provide sufficient information to determine the need to change PARs. While field monitoring data can be useful, it is not appropriate to wait for that data to become available if other data demonstrate the need to expand the PAR.		
9.8	EP01	**Question** Withdrawn following discussion at EP workshop.	Discussed at EP Workshop. Withdrawn. Withdrawn 7/12/00	Amergen
		Response:		

FAQ Log 9

Temp. No.	PI	Question/Response	Status	Plant/ Co.
9.10	MS01 MS02 MS03 MS04	**Question** 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. 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? **Response** Not if the diesel passes the test and the requirements of the paragraph that starts on line 31 of page 26 of NEI 99-02 are met. If the diesel fails the test, the entire test time would be counted as unavailable time, or any portions of the test that do not meet the requirements of the cited paragraph would be counted as unavailable time.	Added 6-1-00 Discussed 6/14/00 Revised 6/14/00 On hold pending NRC review 7/12/00 - Approved	Susquehanna

FAQ LOG 10

Temp No.	PI	Question/Response	Status	Plant/ Co.
10.2	MS02	**Question:** Question withdrawn per NRC request (7/11/00)	Withdrawn per NRC request.	NRC
10.3	PP01	**Question:** **Withdrawn** **Response:**	Discussed 6/14/00 On hold, Dominion review ongoing. 7/12/00 - Withdrawn	NRC
10.4	MS01 MS02 MS03 MS04	**Question:** Is it necessary to perform a risk assessment to show that an overhaul maintenance activity is of low risk in order to exclude the hours in the unavailability indicator? **Response:** Yes. 10 CFR 50.65a(4) requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. The rule will be effective on November 28, 2000. Guidance on actions necessary to comply with the rule are contained in NUMARC 93-01, Revision 2. Section 11, as revised February 22, 2000, of this document provides guidance for the development of an approach to assess and manage the risk impact expected to result from the performance of maintenance activities. In the interim to qualify for the exclusion of unavailable hours from the unavailability indicator, licensees must perform that assessment and demonstrate that the planned configuration meets the requirements for normal work controls, as identified in Section 11.3.7.2 of NUMARC 93-01. Otherwise the unavailability hours must be counted.	Discussed 6/14/00 On hold, NEI review ongoing. Response revised, 7/11/00 (NRC) 7-12-00 On hold, NRC and NEI actions to confirm consistency with MR revision and associated guidance. Intent to finalize at next meeting.	NRC
10.5	MS01 MS02 MS03 MS04	**Question:** Is it appropriate to use the default value, that is, the period hours, for the hours that each EDG train is required to be operable when not all trains are required to be operable during shutdown? This results in a non-conservative performance indicator. **Response:** No. The default values in the guidance were provided as an option for licensees to use to reduce the data collection burden. In some cases, the default value is conservative. In other cases, such as with the EDGs, it may be non-conservative. The default values may be used when they are conservative. The non-conservative default values may not be used and the actual hours the train is required to be operable must be determined.	Discussed 6/14/00 On hold, NEI and NRC review ongoing	NRC

FAQ LOG 10				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
10.7	OR01	**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? **Question (proposed alternate wording, NRC, 7/11)** A post survey was not completed until approximately 4 hours after a resin sluicing evolution was completed, which produced dose rates greater than 1000 mrem per hour at 30 cm from the spent resin liner. The licensee's Technical Specifications require such an area to be controlled as a locked high radiation area. Once performed the radiation survey indicated that the dose rates exceeded those allowed by Technical Specifications. However, the area remained unguarded and unlocked for an additional 20 hours before it was controlled in accordance with the Technical Specification. Do these events constitute "concurrent nonconformances" as used in the Performance Indicator definition, and therefore, one PI occurrence? **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. **Alternate Response to alternate question (NRC 7/11/00)** No. The definitions for both the Technical Specification High Radiation Area Occurrence and the Very High Radiation Area Occurrence start out "A nonconformance (or concurrent nonconformances) with .." [Technical Specifications, or 10CFR20, respectively]. As used in these definitions, concurrent means "existing at the same time and resulting from the same cause." During the first four hours of this example, the failure to perform a timely radiation survey was the cause of the failure to post the area, control access to the area, and provide dosimetry as required by Technical Specifications. They are therefore concurrent nonconformances and constitute a single PI count. However, after the survey was performed, the failure to establish proper controls over access to the area in a timely manner was caused by another programmatic breakdown that could not be considered the same as or concurrent with the failure to perform the survey. This is an example of a sequential failure that warrants a second PI count. **Alternate Response to original question (NEI 7/11/00)** Although the occurrence may involve several nonconformances, there was only one occurrence of "loss of radiological control over access or work activities within the respective high-radiation area (>1 rem per hour)." However, follow-up inspection of the occurrence using the significance determination process (SDP) may result in more than one finding, e.g., in the areas of occupational radiation safety and problem identification and resolution, due to the number and the nature of the nonconformances.	Discussed 6/14/00 On hold, NEI review ongoing Discussed 7/12/00 NRC/NEI action to propose/review alternate question/response	NRC

FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.1	EP03	**Question:** **Appendix D – Grand Gulf** Of the 43 sirens associated with our Alert Notification System, two of the sirens are located in flood plain areas. During periods of high river water, the areas associated with these sirens are inaccessible to personnel and are uninhabitable. During periods of high water, the electrical power to the entire area and the sirens is turned off. The frequency and duration of this occurrence varies based upon river conditions but has occurred every year for the past five years and lasts an average of two months on each occasion. Assuming the sirens located in the flood plain areas are operable prior to the flooded and uninhabitable conditions, would these sirens be required to be included in the performance indicator during flooded conditions? **Response:** If sirens are not available for operation due to high flood water conditions and the area is deemed inaccessible and uninhabitable by State and/or Local agencies, the siren(s) in question will not be counted in the numerator or denominator of the Performance Indicator for that testing period.	Approved 7/12/00	GG Entergy
11.2	MS01	**Question:** **(This FAQ is a proposed replacement for FAQ 169. Upon approval, FAQ 169 would be withdrawn)** Are Technical Specification required monthly Emergency Diesel Generator surveillance tests counted as unavailability for this PI? Actions to restore the EDGs during surveillance testing could be considered complex. However, it seems unreasonable to count these required surveillance tests as unavailability, considering the fact that the EDG is powering the Engineered Safeguards bus in parallel with the grid for the majority of the test. **Response:** Yes, Technical Specification required monthly Emergency Diesel Generator surveillance tests are counted as unavailability for the SSU PI unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. See NEI 99-02 Revision 0, page 26, lines 31 through 40.	FAQ response expands on response currently provided to FAQ 169. 7/12/00 – Approved.	NEI

FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.3	MS03	**Question:** Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question. **PART A** CR-3 has two EF System pumps and associated piping systems that are credited for Design Basis Accidents of Loss of Main Feedwater, Main Feedwater Line Break, Main Steam Line Break, and Small Break LOCA. A design criterion for the EF System is that a maximum time limit of 60 seconds from initiation signal to full flow shall not be exceeded for automatic initiation. Pumps EFP-2 (steam turbine driven) and EFP-3 (independent diesel driven) are auto-start pumps and are tested for the 60-second time criteria. EFP-3 was installed in 1999 to replace a third pump, the electric motor driven (EFP-1) pump, due to emergency diesel generator electrical loading concerns in certain accident scenarios. Per FSAR Section 10.5.2, "MAR [modification approval record] 98-03-01-02 installed a diesel driven Emergency Feedwater Pump (EFP-3) to functionally replace the motor driven Emergency Feedwater Pump (EFP-1) as the "A" EF Train." The motor driven pump does not receive an automatic start signal. The motor driven pump is interlocked with the diesel driven pump so that if the diesel driven pump is operating, EFP-1 will be tripped or its start inhibited. The motor driven pump is maintained for defense-in-depth. EFP-1 can be used to transfer water from the condenser hotwell into the steam generators during a seismic event, if long term cooling is necessary. EFP-1 can be used as a backup to EFP-2 to supply EFW to the steam generators for fires in the Main Control Room, Cable Spreading Room, and Control Complex HVAC Room. CR-3 is reporting RROP safety system unavailability performance indicator data on the basis of two EF pumps and trains. CR-3 is not reporting on EFP-1. CR-3 design and usage of EFP-1 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0. EFP-1 is safety-related and tested. However, EFP-1 is not required to be OPERABLE in any MODE in accordance with the Improved Technical Specifications (ITS). EFP-1 cannot replace EFP-3 to meet two train EFW ITS requirements. EFP-1 is included in the PRA but is not a "risk significant" component. EFP-1 is credited in the FSAR as noted above for providing defense-in depth and maintained for potential use in certain seismic and Appendix R conditions. Should this be reported as a third train of AFW?	7/12/00 – Action to establish conference between CR and NRC.	Crystal River
		Response:		

FAQ LOG 11

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

FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.6	Gen	**Question:** FAQ 170 discusses correcting past unavailability hours for Emergency AC System surveillance testing which were found to be incorrectly reported to WANO. The FAQ response states that historical data does not have to be revised, except to ensure that the data is accurate back to the first quarter of 2000. Can this response be applied to any correction of performance indicator data that occurred in the historical (prior to first quarter of 2000) data time period? **Response:** Data in the historical submittal (through the end of 1999) does not require correction. However, previous data may be revised by the licensee if desired and as described and allowed by NEI 99-02.	7/12/00 -- Discussed. On hold for review.	
11.7	MS02	**Question:** In NEI 99-02, under the <u>Support System Unavailability</u> header, it is identified that in some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling *<u>need not be reported</u>* if cooling water from another source can be substituted. The rules further state that if both the monitored and support system pumps are powered by a class 1E electric power source, then a pump powered by a non- class 1E source may be substituted provided the redundancy requirements to accommodate single failure requirements for electric power and cooling water are met. At RBS, the HPCS pump room is cooled by a safety related unit cooler, HVR-UC5. This unit cooler has non-safety related/non-Class 1E powered Normal Service Water (NSW) supplied to it and a safety related/Class 1E Standby Service Water (SSW) supplied to it as a backup cooling source. The SSW system has four 50% capacity pumps, two per train. Both trains of SSW merge into a common header at the unit cooler. If we remove one train of SSW from service can NSW be credited as a substitute thus keeping HVR-UC5 and the HPCS pump available? **Response:** In this case, no substitution is required, since the HPCS system is still available. Removal of one 100% train of SSW from the unit cooler has no effect on the availability of HPCS since one 100% train of SSW is still available to service the HVR-UC5 unit cooler. The single failure criteria should only be applied to cases where there is <u>substitution of the support system</u> and in cases where the <u>mitigating systems have installed spares or redundant trains.</u>	7/12/00 Discussed. On hold for review.	River Bend
11.8	MS01 MS02 MS03 MS04	**Question:** Our Standby Service Water System (SSW) is designated as a Support System for each of the four mitigating systems. The system has two trains and each train has two 50% capacity pumps. At the mitigating system interface, the SSW support system either has both trains of SSW supplied to the cooling load or one SSW train exclusively supplying the cooling load. A train with one pump in service will supply the required SSW loads except the RHR train. The RHR train is normally valved out of service and is manually lined up to support a design basis accident condition some time after the automatic initiation sequence is completed. We consider all mitigating systems within a train, except RHR in that train, available with one SSW pump out of service. However, RHR, with the SSW from the other train available, is considered available. Have we calculated the availability correctly? **Response:** Yes. The mitigating systems that can be supplied by a single SSW train with one SSW pump in service are available.	7/12/00 Discussed. On hold for review.	River Bend

FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.9	MS02	**Question:** On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as "The ability of the monitored system to take suction from the condensate storage tank **or** [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel." However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI? **Response:** Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of both paths.	7/12/00 Discussed. On hold for review.	NRC
11.10	BI01	**Question:** **Proposed replacement for FAQ 193** The definition of the RCS Specific Activity PI is the maximum RCS activity as a percentage of the technical specification limit. Should licensees with limits more restrictive than the technical specifications use the more restrictive limit or the TS limit? **Response:** Licensees should use the most restrictive regulatory limit (e.g., technical specifications or license condition). However, if an administrative limit is in place due to uncertainty about compliance with 10 CFR Part 100 using the regulatory limits, licensees should use the highest administrative limit that ensures compliance with 10 CFR Part 100.	7/12/00 Discussed. On hold for review.	NRC
11.11	IE03	**Question:** Regarding the Unplanned power change PI, I have the following questions: 1. Is the 20% full power intended to be 20% of 100% power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97)= 19%] 2. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate? **Response:** 1. It is intended to be 20% of 100%. 2. Licensees should use the most reliable indication of power.	7/12/00 Discussed. On hold for review.	NRC
11.12	IE03	**Question:** **(Question being rewritten for clarification)** **Response:**	7/12/00 Discussed. Action, NRC to rewrite question and response for clarification.	NRC

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Temp No.	PI	Question/Response	Status	Plant/ Co.
11.13	EP01	**Question:** Regarding taking credit for notification performance opportunities, NEI 99-02, page 91 defines opportunities for notifications as those made to the state and/or local government authorities. The guidance further defines timely as those offsite notifications that are initiated must be verbal in nature. On page 92 under clarifying notes (second paragraph), NEI 99-02 states that notifications may be included in the PI if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. This particular note applies to operating shift simulator evaluations, not emergency drills. Can credit can be taken for the notification performance opportunity when notifications are simulated during emergency drills (i.e., not operator simulator evaluations), with no actual verbal contact, as long as the procedures are completed up to the time the notification is made.? **Response:** 99-02 allows for the simulation of notification of offsite agencies in the case of simulator based drills. There is no reason not to allow the same simulation for other EP drills. However, since the guidance in NEI 99-02 seems specific to simulator drills, it has been interpreted as not allowing such simulation for other drills. The guidance will be clarified in a future revision of the document. It is not expected that State/local agencies be available to support all drills conducted by licensees. The drill should reasonably simulate the contact and the participants should demonstrate their ability to use the equipment. Generally, the contact is simulated through the use of a controller answering a phone. Although this method will not test the equipment, communications tests are required by Appendix E to 10 CFR 50 and the Emergency Plan should delineate such tests.	7/12/00 – On hold, NRC review/revision	NRC
11.14	EP03	**Question:** A licensee recently had a regularly scheduled silent siren test failure. Immediately following the test failure, a request to test the sirens from an alternate location (the local county has 74 sirens that can be activated from either one of two locations) was performed and it failed as well. My question is how many tests should be counted in the PI? My read on the guidance leads me to believe that only the first set of failures should be counted since that was the "regularly scheduled" test. The second test was somewhat of a troubleshooting test. There is some confusion among the licensee's staff as to how many tests should count. Some people also think that the post maintenance tests should be counted. I don't think that this indicator should be treated like the EP drill and exercise performance PI (i.e., if the PI is low, a licensee can do more drills to bring up the PI). Counting more successful siren tests (either post maintenance or troubleshooting) would mask the true reliability of the siren system that's being measured during the regularly scheduled tests.	7/12/00 – On hold, NRC review/revision	NRC

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Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
		Response: One. The failure of the first system should be a failure and the backup system should not be an additional failure, nor should it be counted as a success if it were successful. The purpose of the PI is to give an indication of the manner in which the licensee maintains important EP equipment. This being the case, it is not appropriate to count the back up system success rate. The test should not be 2 failures (by the way since all the sirens failed, we are talking about 1 or 2 times the # of sirens as the number of failures). Site procedures for activation of the siren system vary. Some procedures may include use of the back up system should the main system fail.		
11.15	PP01	**Question**: If perimeter intrusion equipment, CCTV monitoring equipment or systems supporting their functionality are damaged or destroyed by environmental conditions and remains unable to perform their intended function after the condition subsides (e.g., a lightning strike, wind, ice, flood) do you need to count any hours towards the performance indicator?	7/12/00 Discussed. On hold for review.	\ComEd
		Response:		
11.16	PP01	CLARIFICATION NEEDED ON "FAQ" # ID-59 ISSUED WITH NEI 99-02 REV. 0 MARCH 28 2000 -- "COMP. POSTING FOR NON-FAILURE OF EQUIPMENT" In FAQ 59 and resulting response it states in part that, if an IDS system segment needs to be declared inoperable due to a Security Plan commitment of "x" number of false alarms received, the zone would need to be comped, repair / test the segment, return to operable and remove the comp post. In the response it goes on to state that if there is no equipment malfunction and the system would still have alarmed during intrusion (still capable of performing its intended function) then the man hours that were established as part of the "precautionary maintenance" activity would not be counted. **Question:** If the zone / segment remains operable (still capable of performing its intended function) but is "declared" inoperable due to a Security Plan commitment of "x" number of false alarms received is it necessary to have maintenance "check" the zone / segment prior to declaring the zone operable? Or, can functional testing be conducted by security on that zone / segment assuring that it was capable of alarming during an intrusion?	7/12/00 Discussed. On hold for review.	ComEd
		Licensee Proposed Response:		
11.17	MS01 MS02 MS03 MS04	Question: Withdrawn due to similarity to FAQ 9.2	Withdrawn	Quad Cities /ComEd
		Response:		

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Temp No.	PI	Question/Response	Status	Plant/ Co.
11.18	MS01	**Question:** The station UFSAR states that operator actions are required to restore the EDG room ventilation system following: 1) a fire protection system actuation 2) a HELB occurring outside of the EDG rooms. The restoration actions (manually open several sets of dampers) are directed by an operating procedure. During certain fire protection system surveillances, the EDG room ventilation system dampers are closed to the same configuration as when a HELB or fire protection system actuation occurs. No other actions are taken that would otherwise affect EDG start and load capability. The steps necessary to return the ventilation subsystem to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individual specifically involved with restoring the ventilation is briefed on the time restraints and dedicated to the testing. Since the UFSAR credits the operator actions required to restore the system to its normal operating configuration following a fire protection actuation or HELB, the actions taken to restore ventilation during testing would be similar to those credited in the UFSAR. Can the EDG be considered available during the period the room vent fan is unavailable due to the fire protection surveillances?	Pending	Braidwood /ComEd
		Response:		
		Question:		
		Response:		
		Question:		
		Response:		