Initiating Events

IE01 Unplanned Scrams

ID 455

Posting Date 07/16/2008

Question On March 22, 2008 Reactor Feedwater (RFW) pump 1B (RFW-P-1B) experienced a speed transient which caused both RFW pump low suction pressure alarms to actuate. In response, control room staff initiated a reduction in reactor recirculation pump speed (both pumps) to reduce core flow (which reduces power) as directed by procedure. The core flow reduction was terminated after both RFW pump low suction pressure alarms cleared, as allowed by procedure. Upon termination of the flow reduction the operators assessed key plant parameters, including reactor power using the 1-minute average core thermal power (CTP) signal, and, after about 15 minutes, the 15-minute average CTP signal, and concluded that plant power was at 81% (as documented in the Condition Report and operating logs). The 1-minute and 15-minute average CTP signals are calculated using the reactor heat balance and are the normal signals used by operators to monitor and control plant power level. The 1-minute average CTP signal is driven by RFW flow and does not provide an accurate power calculation during RFW flow transients. It was not used by operators to assess power conditions during the initial RFW flow transient.

Subsequently, the control room staff requested that the Station Nuclear Engineer (SNE) provide an evaluation of peak power achieved during the transient to determine if reactor power exceeded 102% of the operating license limit. The SNE ultimately provided a plot of reactor power using an APRM simulated heat flux signal, which is not a signal used to control reactor power, nor is it a signal that is normally monitored by Operations personnel. The APRM simulated heat flux signal (a six second average of a single APRM signal, available for two of the APRMs) indicated that power had initially increased before the RFW control system recovered and brought speed (and power) back down. Since the RFW pump low suction pressure alarms did not clear at that point, operators reduced core flow. The APRM simulated heat flux signal indicates that power then went 1-3% below 80% RTP before settling out at approximately 81% RTP as conditions stabilized. Immediately following the transient the APRMs and APRM recorders were consulted for the purpose of assessing the condition of the core, but not for the purpose of assessing plant power level.

As cited above, guidance on what indications to use to determine if a change of greater than 20% of full power has occurred is Licensees should use the power indication that is used to control the plant. In this event the operators documented a reduction in power to approximately 81% RTP using indications available to them immediately following the transient (i.e., the 1-minute average). In addition, per Columbia operating procedures the primary power indication used to control and monitor the plant reactor power, including monitoring compliance with our license condition for reactor power, is the 15-minute average CTP signal, which is calculated using the reactor heat balance. This signal also indicated a reduction in power to approximately 81% RTP.

FAQ 227 (dated 10/31/2000) appears to be the question that led to the guidance quoted above. This FAQ asked, For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate? The response was, Licensees should use the power indication that is used to control the plant at the time of the transient. In this case the operators were not controlling the plant in response to indicated power but were reducing core flow in response to the alarms. Cessation of the flow (and power) reduction was dictated by the clearing of the RFW pump low suction pressure alarms. Upon checking power level following the transient, using the 1-minute average CTP signal, it was determined that power was reduced to 81% CTP (as documented in the CR and the operating logs). The APRM simulated heat flux signal was clearly not used to control the plant, nor was it initially consulted to determine final power level or the extent of the transient. The wording of the guidance and the FAQ 227 question and response would indicate that the licensee is not required to find or use the more accurate indications when assessing the power change, but should use initial indications of the power level. In this case the CR, operating logs, 1-minute average CTP signal, and 15-minute average CTP signal all indicate a reduction to 81% RTP.

RIS 2007-21 generated a significant amount of discussion about monitoring of instantaneous power in Boiling Water Reactors (BWRs) and resulted in some agreement that an average CTP calculation is the best way of monitoring power. However, these calculations have inherent inaccuracies during transient conditions, particularly RFW flow transients. APRMs serve a primary purpose of performing a reactor protective trip function and also have accuracy issues as far as indication of instantaneous core thermal power. As such, they provide more insights to transient conditions, but are not as accurate for absolute power indication, and, in fact, the APRMs are calibrated against the average CTP signal.

NRC Region IV has indicated that they do not agree with use of the 15-minute average CTP signal for assessing the event because events of a different type (multiple transients or power oscillations) would be invisible or inaccurately assessed. They cite the example discussion on page 14, lines 23-30 of NEI 99-02, Revision 5, as a case where a 15-minute average would not lead to assessment of two separate unplanned power changes of greater than 20% due to the signal averaging over a relatively long period of time.

In addition, NRC Region IV considers that the reference in NEI 99-02, page 15, lines 14-15, to "use the power indication that is used to control the plant" should include all indications that are normally available to the operators for controlling plant power. For example, in response to a quickly developing transient, such as during plant response to a component failure, power indication averaged over 15 minutes may not be appropriate for controlling power whereas APRM's may be a better indicator for the operators to use during the transient response. In contrast, during a slowly developing transient, such as a controlled reduction in power, a power average may be appropriate.

Response The purpose of the indicator is to monitor the number of unplanned power changes (excluding scrams) that could have, under certain plant conditions, challenged safety functions with the intent of providing leading indication of risk-significant events (per NEI 99-02). FAQ 227 provided clarification that detailed analysis of exact core conditions is not required to meet the intent of the indicator. This PI does not specify the use of secondary calorimetric averaging (i.e., heat balance equation) to compute changes in reactor power, only that licensees are required to use the method of power determination that is used to control the plant. However, it is recognized that some power indications that are used to control the plant are not appropriate during a transient, (i.e. 15 minute calorimetric power averaging). In these situations, other indications and/or procedural guidance need to be consulted that could provide a reasonable assurance that a power change of greater than 20% did or did not occur.

In the event described above, the transient involved a brief increase in feedwater flow, which caused the RFW pump low suction alarm to activate. The operators reduced pump speed to reduce flow as directed by procedure. Initial indications following completion of the transient indicated that power stabilized at 81% power using a 1 minute power average. Since the event started at 100% power and power initially stabilized at 81% power at the end of the event the gross power change was approximately 19%; therefore, this value does not meet the reporting criteria for the PI.

No guidance change.

ID 442

Posting Date 03/19/2008

Question On June 21, 2007, a planned plant shutdown was commenced with the intent of completing the shutdown with a manual scram. The purpose of the shutdown was to repair a valve associated with a reactor recirculation pump. This issue was discovered on June 4, 2007.

At approximately 0100 on June 22, 2007, at approximately 43.1% core thermal power (43.6% neutron flux), Operations performed an A and B Reactor Recirculation Pump downshift. At this point, Operations expected to observe a power reduction of approximately 12%. The B Reactor Recirculation Pump tripped instead of shifting to slow speed. This resulted in a power change that dropped to approximately 26.1% core thermal power (21.6% neutron flux), leveling out at approximately 26.1% core thermal power (23.3% neutron flux). A thermal power graph that was subsequently obtained from the plant computer indicates that power briefly increased from approximately 43.1% power to approximately 46.9% power before the power decrease. Reactor Engineering believes that the brief indicated power increase was indication only and does not reflect actual power level. Average Power Range Monitors indicated a neutron flux change of 22.0% during this transient.

The shutdown was then completed with a planned manual scram from approximately 23% in accordance with normal plant procedures. This scram was not counted as it was completed in accordance with normal plant procedures, but is the subject of another FAQ.

This was not counted as an Unplanned Power Change because the power change met the 72-hour criterion established on NEI 99-02, Rev 4, page 16, line 40, through page 17, line 4. Lines 10 through 14 state that equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair are not counted as part of this indicator if they are repaired during the planned power reduction. However, if during the implementation of a planned power reduction, if power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred. In this case, power was not reduced by more than 20% of full power beyond the planned reduction. Therefore, FENOC does not believe that this power change counts toward the indicator because the unplanned portion of the evolution was not more than approximately 10%. This is similar to FAQ 2, which is reflected on page 17, lines 12 14, of NEI 99-02, Rev 4. These lines were added in Rev 1, while incorporating the FAQ resolution.

Should an unplanned power change be counted and reported under IE-3?

Response Since the unexpected portion of this unplanned power change was not more than approximately 10% of full reactor power, it should not count toward the Unplanned Power Change PI.

No revision to the guidance is required.

ID 439

Posting Date 03/19/2008

Question On June 21, 2007, a planned plant shutdown was commenced with the intent of completing the shutdown with a manual scram. The purpose of the shutdown was to repair a valve associated with a reactor recirculation pump. This issue was discovered on June 4, 2007.

At approximately 0100 on June 22, 2007, Operations performed an A and B Reactor Recirculation Pump downshift. The resulting downpower is the subject of another FAQ.

The shutdown was then completed with a planned manual scram from approximately 23% in accordance with normal plant procedures. This scram was not counted as the shutdown was planned and was completed in accordance with normal plant procedures.

The shutdown was not counted as an Unplanned Scram due to the following guidance from NEI 99-02, Revision 4.

Page 9, line 21, states that the indicator monitors unplanned scrams.

Page 10, lines 11 through 14, define an unplanned scram as a scram that was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This scram was intentional, planned, and was directed by a normal operating procedure.

Page 10, lines 36 through 45, provides examples of types of scrams that are included. This scram does not fit any of those examples.

Page 11 provides examples of scrams that are not included. Lines 4 and 5 exclude scrams that are part of a normal planned operation or evolution. This scram meets that criterion. Lines 10 and 11 exclude scrams that occur as part of the normal sequence of a planned shutdown. FENOC believes that his scram meets that criterion.

In addition SECY 99-07A states The objective of the Initiating Events cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions. Such an event can lead to either an automatic scram when a plant parameter exceeds a set point, or a manual scram when directed by an abnormal procedure or an emergency operating procedure. In addition, operators are trained to manually scram the reactor if an automatic scram is unavoidable. A manual scram, therefore, may be implemented for the same or similar plant conditions that would cause an automatic scram, and the effect on the plant is the same - to upset plant stability and challenge critical safety functions. This indicates that the purpose (objective) of this PI is to count those events that either resulted in an automatic scram or resulted in the need to manually scram the reactor with some immediacy (with no preplan). This scram was pre-planned and was conducted in accordance with the normal shutdown procedure; it was not taken as a reaction to plant conditions that were, or were believed to be, precursors to an automatic scram and was not directed by an abnormal or emergency operating procedure. Therefore, FENOC believes that this shutdown does not represent an Unplanned Scram.

Should this scram be counted as an unplanned scram and reported under IE-01?

Response The staff believes that the two Perry scrams on June 22 and June 29, 2007, should count toward the Unplanned Scrams per 7000 Critical Hour performance indicator. NEI 99-02 provides examples of scrams which are included in the indicator, the examples include those scrams that results from unplanned transients, equipment failures, spurious signals, human error, or those directed by abnormal, emergency, or annunciator response procedures. The guidance also states that scrams that occur as part of the normal sequence of a planned shutdown are not included in the indicator.

Perry experienced two equipment failures which resulted in the plant being in single loop operations. In both events, the licensee shutdown (by scram) from single loop, with the turbine on-line, and at a power level higher than the licensees normal sequence for a planned shutdown.

The working group has addressed similar FAQs in the past and the staff has consistently ruled that if the licensee does not follow its normal method of shutting down the plant due to problems that challenge plant operations, the scram should be included in the indicator.

ID 436

Posting Date 12/05/2007

Question Duane Arnold experienced a reactor water chemistry excursion (increasing conductivity readings while performing condensate demineralizer manipulations) at approximately 1630 on March 18, 2007. This excursion occurred with the plant operating at ~34% power during a post Refueling Outage startup. By 1630, the conductivity level quickly surpassed the Technical Requirements Manual (TRM) limits of >1 and >5 (µmoh/cm). This resulted in actions being initiated as required by the TRM for restoring the limits immediately and analyzing a sample within 8 hours. At the time, conductivity was > 10.

The plant also entered the TRM requirement to be in Mode 3 within 12 hours and be in mode 4 within 36 hours as a result of the out of specification chemistry parameters.

As a result of the TRM and PCP LCOs, the plant commenced a shutdown in accordance with Integrated Plant Operating Instruction (IPOI) 4, Plant Shutdown, Section 6.0, Fast Power Reduction. This IPOI consolidates information for a safe and efficient shutdown from 35% power operation to cold shutdown or other shutdown conditions, and is not an AOP.

The guidance provided in NEI 99-02, Revision 4 clearly supports the March 18, 2007 scram not being considered an unplanned scram. On page 10, lines 11 and 12, the guidance defines an unplanned scram as "*Unplanned scram* means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure." The March 18, 2007 scram was clearly part of the normal Duane Arnold shutdown and the scram was initiated in accordance with the Integrated Plant Operating Instruction, (IPOI) 4, Shutdown."

The NRC Resident does not agree with the Duane Arnold position as he considers the fast power reduction of Integrated Plant Operating Instruction, (IPOI) 4, Shutdown" to be an abnormal section of a normal procedure and therefore concludes the scram should count as unplanned.

<u>Is it the correct interpretation that the above event should be not be considered an unplanned scram with respect to the NRC indicator?</u>

Response **Appeal Decision:**

Yes, the scram counts under the Unplanned Scram PI, consistent with the guidance of NEI 99-02, page 11, line 10. While the unit shutdown in accordance with a section of their "normal shutdown" procedure, that portion of the procedure was not normally invoked for planned shutdowns, and did not contain the normal sequence of activities associated with planned shutdowns. Rather, that section of the procedure was typically used for response to chemistry transients associated with condenser performance issues.

Not to be used for future reference or incorporation into NEI 99-02.

Initiating Events

IE01 IE03

ID 440

Posting Date 03/19/2008

Question On June 27, 2007, while operating at 86% reactor power, a reactor recirculation pump motor experienced a fault. As a result, the plant experienced a power runback to 55% reactor power. This was counted as an Unplanned Power Change.

The decision was made to shutdown the reactor by a manual reactor scram in accordance with the normal shutdown procedure. An outage schedule was developed that included the decision to scram the plant, this decision was communicated to plant employees, and the operating crew that would be scramming the plant practiced the scram on the simulator.

On June 29, 2007, in order to repair the pump motor fault, Operations entered their normal shutdown procedure, IOI-8, and shutdown the plant by manually inserting a scram in accordance with that procedure. This procedure is intended to be used during a non-emergency condition with plant conditions stable. The shutdown was originally not counted as either an Unplanned Scram or an Unplanned Power Change, but will be counted as an Unplanned Power Change.

The shutdown was not counted as an Unplanned Scram due to the following guidance from NEI 99-02, Revision 4.

> Page 9, line 21, states that the indicator monitors unplanned scrams.
>
> Page 10, lines 11 through 14, define an unplanned scram as a scram that was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This scram was intentional, planned, and was directed by a normal operating procedure.
>
> Page 10, lines 36 through 45, provides examples of types of scrams that are included. This scram does not fit any of those examples.
>
> Page 11 provides examples of scrams that are not included. Lines 4 and 5 exclude scrams that are part of a normal planned operation or evolution. This scram meets that criterion. Lines 10 and 11 exclude scrams that occur as part of the normal sequence of a planned shutdown. This scram meets that criterion.

In addition SECY 99-07A states The objective of the Initiating Events cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions. Such an event can lead to either an automatic scram when a plant parameter exceeds a set point, or a manual scram when directed by an abnormal procedure or an emergency operating procedure. In addition, operators are trained to manually scram the reactor if an automatic scram is unavoidable. A manual scram, therefore, may be implemented for the same or similar plant conditions that would cause an automatic scram, and the effect on the plant is the same - to upset plant stability and challenge critical safety functions. This indicates that the purpose (objective) of this PI is to count those events that either resulted in an automatic scram or resulted in the need to manually scram the reactor with some immediacy (with no preplan). This scram was pre-planned and was conducted in accordance with the normal shutdown procedure; it was not taken as a reaction to plant conditions that were, or were believed to be, precursors to an automatic scram and was not directed by an abnormal or emergency operating procedure. Therefore, FENOC believes that this shutdown does not represent an Unplanned Scram.

The shutdown was not counted as an Unplanned Power Change due to the following guidance from NEI 99-02, Revision 4.

> Page 16, line 3, states that the indicator monitors the number of unplanned power changes (excluding scrams). Since this shutdown was a planned manual scram, it is excluded from the indicator.
>
> Page 16, lines 9 and 10, defines the indicator as excluding manual and automatic scrams. Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 16, line 15, tells the licensee to report the number of unplanned power changes, excluding scrams. Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 17, line 18, excludes manual scrams. Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 18, lines 31 through 33, directly addresses this situation. It states that if an off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor trip using normal operating procedures, only an unplanned power change is counted. The unplanned power change from 86% to 55% was counted; in accordance with this section, the planned reactor trip using normal operating procedures was not counted.

FENOC determined that this issue should count as an unplanned power change because the power change from 55% to 0% occurred within 72 hours of identifying the issue (i.e., the recirculation pump trip)

Should this scram be counted as an unplanned scram or as an unplanned power change, or should it not be counted toward either indicator?

Response The staff believes that the two Perry scrams on June 22 and June 29, 2007, should count toward the Unplanned Scrams per 7000 Critical Hour performance indicator. NEI 99-02 provides examples of scrams which are included in the indicator, the examples include those scrams that results from unplanned transients, equipment failures, spurious signals, human error, or those directed by abnormal, emergency, or annunciator response procedures. The guidance also states that scrams that occur as part of the normal sequence of a planned shutdown are not included in the indicator.

Perry experienced two equipment failures which resulted in the plant being in single loop operations. In both events, the licensee shutdown (by scram) from single loop, with the turbine on-line, and at a power level higher than the licensees normal sequence for a planned shutdown.

The working group has addressed similar FAQs in the past and the staff has consistently ruled that if the licensee does not follow its normal method of shutting down the plant due to problems that challenge plant operations, the scram should be included in the indicator.

Initiating Events

IE03 Unplanned Power Changes

ID 457

Posting Date 07/16/2008

Question NEI 99-02 page 14, lines 42 through 49 and page 15, lines 1 through 4 state: *Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted unless they are reactive to the sudden discovery of off-normal conditions. However, unique environmental conditions which have not been previously experienced and could not have been anticipated and mitigated by procedure or plant modification, may not count, even if they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine or other biological growth from causing power reductions. Intrusion events that can be anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would normally be counted unless the down power was planned 72 hours in advance. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.*

The NEI ROP Task Force and the NRC staff have in the past reviewed many repeat FAQs from various plants related to the exception in IE02, Power Changes Greater than 20%, from counting events caused by expected environmental problems. Typically FAQs are generated not because the sites resident inspector feels the plants response was inadequate but because NEI 99-02 dictates it. The generation of such FAQs is an inefficient use of the industrys and NRCs time. Once the original FAQ (and implicitly the plants plans and procedures for dealing with future similar events) has been approved, the site resident inspector should be allowed to make the determination whether the plants response was timely and adequate. An FAQ should only be required if the resident inspector and plant do not agree the guidance has been met as is the case with the other indicators.

Response The subject text should be replaced with the following :

Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, animal intrusion, environmental regulations, or frazil icing) may qualify for an exclusion from the indicator. The licensee is expected to take reasonable steps to prevent intrusion of animals, marine debris, or other biological growth from causing power reductions. Intrusion events that can be anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would normally be counted, unless the down power was planned 72 hours in advance or the event meets the guidance below.

In order for an environmental event to be excluded, any of the following may be applied:

- If the conditions have been experienced before and they exhibit a pattern of predictability or periodicity (e.g., seasons, temperatures, weather events, animals, etc.), the station must have a monitoring procedure in place or make a permanent modification to prevent reoccurrence for the event to be considered for exclusion from the indicator. If monitoring identifies the condition, the licensee must have implemented a proactive procedure (or procedures) to specifically address mitigation of the condition before it results in impact to operation. This procedure cannot be a general Abnormal Operating Procedure (AOP) or Emergency Operating Procedure (EOP) addressing the symptoms or consequences of the condition (e.g., low condenser vacuum); rather, it must be a condition-specific procedure that directs actions to be taken to address the specific environmental conditions (e.g., jellyfish, gracilaria, frazil ice, etc.)
- If the event is predictable, but the magnitude of the event becomes unique, the licensee must take appropriate actions and equipment designed to mitigate the event must be fully functional at the time of the event to receive an exclusion.
- Environmental conditions that are unpredictable (i.e., lightning strikes) may not need to count if equipment designed to mitigate the event was fully functional at the time of the event.
- Downpowers caused by adherence to environmental regulations, NPDES permits, or ultimate heat sink temperature limits may be excluded from the indicator.

The circumstances of each situation are different. In all cases, the NRC Region and Resident Inspectors should evaluate the circumstances of the power change, and if in disagreement with the licensees position, the event should be identified in an FAQ so that a decision can be made concerning whether the power change should be counted. If the event is truly unique, an FAQ should be submitted unless the NRC Region and Resident Inspectors agree with the licensees position.

ID 456

Posting Date 07/16/2008

Question During the spring, the Mississippi River floods as ice melts in the north and spring rains greatly increase the river flow volume. The spring 2008 Mississippi River flooding has been more extensive than flooding seen since Grand Gulf Nuclear Station (GGNS) entered construction and operation. In fact, the Mississippi River levels were higher than any seen since 1973, when the river crested at 51.2 feet, well in excess of installed animal deterrence devices.

GGNS has a service water system that employs a radial well system for its cooling water during normal operation. These radial wells are located closer to the Mississippi River than the plant and are designed to remain functional during flooding in excess of that experienced in the spring of 2008. Although situated over dry land during most of the year, equipment to support the radial wells operation is located on a platform approximately 26 feet above ground level sitting on pilings. The structure is protected from impact by barges or large debris being swept uncontrolled down the river by additional large pilings. A boat is required for station personnel to access the Radial Well Switchgear during times of river flooding.

At 2112 on April 29, 2008, GGNS experienced a loss of Balance of Plant (BOP) Transformer 23 resulting in a loss of the 28AG Bus and Radial Well Pumps E, F, and J. The Loss of Plant Service Water (PSW) Off-Normal Event Procedure (ONEP) was entered as well as the Reduction in Recirculation Flow ONEP. Reactor power was reduced to approximately 47% using Reactor Recirculation flow and control rod insertion. The plant responded as expected. Upon investigation into the loss of BOP Transformer 23, a dead raccoon was found in the vicinity of the transformer which clearly appeared to have come in contact with energized equipment.

The cause of the loss of BOP Transformer 23 is believed to be a short inducted by the raccoon. The flooding of the Mississippi River is believed to have allowed the raccoon to climb into the transformer area bypassing the installed prevention measures. Animal intrusion is normally prevented from the area by removal of ladder access and installed animal deterrence (approximately 8 to 10 feet high above ground) on the power poles adjacent to the transformer structure. These measures prohibit animal intrusion under normally anticipated and expected environmental conditions when animals would be present (.i.e., dry, non-flooded conditions). It was not anticipated or expected that an animal would gain access by swimming in the flooded conditions of the Mississippi River. In order to reach the Radial Well Switchgear, the raccoon either was caught-up in the river or swam a significant distance from the flooded wood line to reach the platform.

The design features were modified following the event to prevent reoccurrence.

<u>Industry Design Standards</u>

IEEE Standard 1264-1993 (R2004), IEEE Guide for Animal Deterrents for Electric Power Supply Substations, documents methods and designs to mitigate interruptions and equipment damage resulting from animal intrusions into electric power supply substations. The standard identifies that there are many animals including birds, mammals, reptiles, and insects that are known or potential sources of animal related outages. The standard states that a mitigation program should be put in place after experiencing an unacceptable level of animal related problems and that survey results indicate that deterrence methods are typically implemented after a substation begins to experience the animal intrusions of concern.

The standard goes on to provide examples of mitigation methods and their reported effectiveness. The standard discusses that a necessary part of the mitigation of animal intrusions is monitoring the effectiveness of installed deterrents for the type of animal and problem the deterrent is intended to mitigate. The standard identifies that often a trail and error approach is necessary to find an effective solution for each problem.

Operating Experience

Based upon previous operating experience, GGNS has implemented measures to mitigate the potential for animal intrusion into critical outdoor equipment. Previous land animal intrusions at GGNS and identified industry events have occurred when the animal approached the area of concern via a land route. This is the first identified event where the animal swam into the area of concern. There has been no occurrence of Radial Well Switchgear water borne animal intrusions in the history of GGNS.

The Mississippi Department of Wildlife, Fisheries and Parks (MDWFP) was contacted to obtain relevant information concerning raccoons. The following information was obtained from a Small Game Biologist for the department.

Under normal river conditions, a raccoon might swim to a know location or island. He would not expect one to swim on purpose in the flood conditions experienced in 2008. MDWFP observed greatly increased numbers of wildlife in areas not normally frequented due to the higher than normal flood conditions.

Raccoons do climb trees and can travel tree to tree. He would not expect a raccoon to travel tree to tree for approximately half a mile over water, swim an extended distance, and then climb a power pole to access a structure (switchgear house). His opinion was its more probable that the raccoon was caught-up in the river and climbed the pole seeking refuge.

Conclusion

The Mississippi River flooding level with an animal intrusion is a unique environmental condition that has not been previously experienced and therefore, could not have been anticipated and mitigated by procedure or plant modification.

Requested Interpretation

Does the GGNS down power of April 29th 2008 count as an Unplanned Power Change per 7,000 Critical Hours?

If licensee and NRC resident/region do not agree on the facts and circumstances explain:

NRC Statement to be include in the Licensees FAQ for the greater than 20% power decrease on April 29, 2008.

Facts:

- In 2002 and 2005, Grand Gulf Nuclear Station had reactor scrams due to raccoons causing ground faults to station transformers in the main station switch yard.
- The corrective actions for the first scram in 2002 did not prevent the scram that occurred in 2005.
- The licensee identified the BOP 23 transformer as vulnerable to animal intrusion following the 2002 reactor scram.

- The Mississippi river level routinely rises in the spring, requiring Grand Gulf employees to use a power boat to perform operator rounds and maintenance checks on equipment at the river.

- In June of 2006, the licensee found an injured raccoon at the base of the BOP 23 transformer. The raccoon had burn marks on its nose and hind legs. The raccoon had come into contact with live current from either the primary or secondary side of one of the platform transformers but did not cause a trip of equipment.

- In response to this event in June of 2006, the licensee placed animal guards on the wooden electrical poles by the transformer platform believed to be approximately 8-10 feet from the ground. They also removed a section of ladder going to the platform approximately 4 feet 7 inch from the ground.

The region and the resident staff have concluded that the environmental conditions which have been previously experienced at the site could have been anticipated by the licensee to mitigate the unintended down power. The staff disagrees with the licensees assertion that the combination of a routine flooding event and repetitive animal intrusion equates to a unique environmental condition. The staff has concluded that, based on the above listed facts, the licensee should have developed corrective actions to mitigate the loss of the BOP transformer by adding animal deterrents that would be effective during flooding events. This would have prevented the occurrence of the April 29, 2008 down power event.

Response This downpower counts toward the indicator. In 2002 and 2005, Grand Gulf experienced reactor scrams due to raccoons causing ground faults to station transformers. The licensee had identified that that the BOP 23 transformer is vulnerable to animal intrusion following the 2002 scram. In June 2006, the licensee discovered an injured raccoon near the base of the BOP 23 transformer and then took corrective actions to attempt to prevent future animal intrusion by installing animal guards and removing portions of a ladder. In addition, the Mississippi River routinely floods the area around the BOP 23 transformer. Although the licensee stated that the combination of the animal intrusion and flooding was the first time this was experienced at Grand Gulf, it was reasonable that the two environmental conditions could be present concurrently and that this should have been taken into consideration when choosing to provide an animal deterrent through a design change (animal guards on the poles). During the event discussions with the licensee, the licensee stated that flooding was not considered when placing the animal guards on the poles. NEI 99-02 states, However, unique environmental conditions which have not been previously experienced and could not have been anticipated and mitigated by procedure or plant modification, may not count, even if they are reactive. Regardless of whether this event was unique, it was within the licensees ability to predict and be prevented; therefore, it counts towards the indicator.

ID 452

Posting Date 05/14/2008

Question On January 3, 2008, Operators at the Browns Ferry Nuclear Plant (BFN) received "TRAVELING SCREEN DP HIGH" alarms and indications of lowering condenser vacuum on all three units. In accordance with general (i.e., not abnormal or emergency) plant operating procedure 2-GOI-200-12*Power Maneuvering,* operators lowered reactor power on Unit 2 to approximately 50%. This action was accomplished in order to maintain condenser vacuum above the turbine trip set point. Unit 2 was returned to 100% power on January 4, 2008, 7:13 AM. The high differential pressure across the screens and the lowering condenser vacuum resulted from Threadfin shad being pulled into the traveling water screens and blocking water flow. On January 6, 2008, at 10:00AM, BFN Unit 2 commenced a subsequent power reduction to 65% in accordance with general plant operating procedures to allow condenser water box cleaning. The cleaning was necessitated by the intake of the fish on January 3, 2008. Unit 2 was returned to 100% power on January 7, 2008, 2:36 AM.

After the power reduction, BFN conducted a review of the event. During this review, it was found that on or before January 3, 2008, a large number of Threadfin shad experienced thermal shock and were drawn into the BFN intake structure causing clogging and damage of the traveling water screens. This reduced the Condenser Circulating Water (CCW) flow and resulted in an unplanned power reduction.

Threadfin shad may experience thermal shock when there is a water temperature change of greater than 2 degrees F in a 24-hour period or when water temperature falls below 45.5°F. For this event, the fish stun likely began during the morning hours of January 2, 2008, when river temperature fell to 45.5°F (~0300 Central Standard Time when intake temp hit 45.5). Shortly thereafter, the temperature reached the greater than 2°F change in 24 hours.

Leading up to the event (on 12/31/07) the river flow was about 10,000 cubic feet per second (cfs) and the ambient river temperature was about 51°F. Due to the low river flow, pooling of heat (warm water) from the plant diffusers had moved upstream and engulfed the plant intake skimmer wall. This is shown by the temperature change at Station 19, which was from 4°F to 8°F warmer than the ambient river temperature. Note that at Station 14, 1.8 miles upstream of the intake skimmer wall, there is no evidence of warm water from the plant (i.e., very little temp change from ambient). Pooling of heat occurs in the river because the diffusers are entraining (i.e., "pulling-in") and warming a volume of river water much greater than what is being supplied by the river flow. This pool of warm water spreads outward (i.e., upstream, downstream, and sideways) until a balance is obtained via heat loss to the ambient water and to the atmosphere.

Due to a cold front entering the valley (and a consequent increase in system power demand), hydro generation "picked-up" late in the afternoon of December 31, 2007. As a result, river flow was increased from 10,000 cfs to between 16,000 cfs and 20,000 cfs. This river flow was sufficient to "push" the pool of warm water downstream of the plant intake skimmer wall. In the early hours of 1/1/08, this eliminated the 4°F to 8°F "swell" in river temperature noted above (see Station 19 plot). At the same time, the cold front also reduced the temperature of the ambient river water by about 5 F, from about 51°F on December 31, 2007 to about 46°F on January 2, 2008. Thus, the aquatic wildlife in the vicinity of the intake was exposed to a total temperature drop of between 9°F and 13°F within about 24 to 36 hours. Most likely, this is what "stunned" the shad, making them lethargic.

Late in the day on January 2, 2008, hydro peaking operations produced peak river flows near 47,000 cfs, lowering the water temperature at Station 19 (i.e., intake skimmer wall) 2°F below the ambient temperature. Late in the morning on January 3, 2008, hydro power peaking operations produced peak river flows near 87,000 cfs, lowering the water temperature at Station 19 another 2°F (a total of about 4°F below the ambient temperature). In these events, the water entering the skimmer wall is below the ambient temperature because at high river flow, the plant withdrawal zone encompasses primarily the shallow overbank areas upstream of the intake. For extreme cold meteorology, the temperature of the water in these shallow areas will be colder than in the main channel of the river. At this point, however, the shad were probably already lethargic (due to the larger drop in temperature between late December 31, 2007 through January 2, 2008).

The drought conditions that existed in the Tennessee Valley during 2007 were most likely a contributing factor in the shad event. The drought conditions in the area were more severe this past year than any time previous in Brown Ferrys operational experience. River flows in the months preceding the event were well below normal. For example, the average river flow past the plant in December 2007 was the lowest in 31 years (see below).

In combination with the waste heat from the plant diffusers, this low flow would have created a larger than normal warm water sanctuary for the shad (e.g., because of low river flow, less heat was flushed downstream) establishing the conditions for a thermal shock event to occur.

While the exact cause for the thermal shock cannot be determined, it can be speculated that either the river flow changes or the cold front or a combination of the two was the cause. As noted above, TVA River Operations had significantly varied river water flows for several days prior to the event to support meeting peak power demands and a cold front had moved into the area. The lower than normal river flows caused by the drought conditions in the valley established conditions such that either mechanism could have caused the temperature change.

BFN Operations normally receives daily river flow projections from TVA River Operations. However, prior to this event, this communication was strictly focused on the need for cooling tower operation to support meeting environmental thermal discharge limits.

Prior to this event, there was little to no ability to predict shad runs similar to that experienced in this event. Lessons learned from this event have enhanced our awareness of some of the combination of conditions that make these runs possible. The cause of this, and similar, runs cannot be absolutely determined, but lessons learned from this event have resulted in actions that have improved our ability to predict and respond to events in the future. These corrective actions focus on better communication with River Operations regarding planned changes to river flows and better preparations when weather conditions may be suitable for a natural temperature drop below 45.5°F. However, these actions are only able to better prepare BFN to mitigate the consequences of such an event should it occur, and can not absolutely prevent future events.

Response The downpowers, caused by environmental conditions and National Pollutant Discharge Elimination System (NPDES) restrictions for plant thermal discharge, were beyond the control of the licensee and could not be reasonably predicted greater than 72 hours in advance.

ID 451

Posting Date 05/14/2008

Question On 1/03/08, Operators at the Browns Ferry Nuclear Plant received "TRAVELING SCREEN DP HIGH" alarms and lowering condenser vacuum on all three units. In accordance with plant procedure 2-GOI-200-12, Power Maneuvering, Unit 2 lowered reactor power to approximately 50% to maintain condenser vacuum above the turbine trip set point. The unit returned to 100% power on 01/04/08, 7:13 AM. This condition resulted from shad being pulled into the traveling water screens and blocking water flow. On 1/06/08, 10:00AM, BFN Unit 2 commenced power reduction to 65% for water box cleanings necessitated by the shad run on 1/03/08. The unit returned to 100% power on 01/07/08, 2:36 AM.

After the power reduction, BFN conducted a review of the event. During this review, it was found that on or before 1/3/08, a large number of Threadfin shad experienced thermal shock and were drawn into the BFN intake structure causing clogging and damage of the traveling water screens. This reduced the Condenser Circulating Water (CCW) flow and resulted in an unplanned power reduction.

It is known that Threadfin shad may experience shock when there is a water temperature change of greater than 2 degrees F in a 24-hour period or when water temperature falls below 45.5°F. For this BFN event, the fish stun actually began during the morning hours on 1/2/08 when river temperature fell to 45.5°F (~0300 Central Standard Time when intake temp hit 45.5). Shortly thereafter, the temperature reached the greater than 2°F change in 24 hours

The exact cause for the thermal shock cannot be determined. TVA River Operations had significantly varied river water flows for several days prior to the event to support meeting peak power demands. A rapid increase in river flow could result in a temperature drop sufficient to result in thermal shock. However, the thermal shock could have occurred naturally. Unusually cold weather or strong winds coupled with cold weather can cause the water temperature to fall to 45.5°F or to be cooled 2°F in 24 hours. These conditions did exist prior to the event.

Another factor was the low amount of rainfall in the previous year which resulted in lower reservoir levels and lower river flows. These factors established conditions where an increase in river flow could result in a more extreme temperature differential. The drought conditions in the area have been more severe this past year than any time previous in Brown Ferrys operational experience.

There is little to no ability to predict these shad stuns. Corrective actions focus on better communication with River Operations and understanding of planned changes to river flows and better preparations when weather conditions may be suitable for a natural temperature drop to or below 45.5 F.

Response The downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. A combination of conditions previously not experienced by the licensee contributed to the large influx of fish into the travelling water screens. Lessons learned from this event, including improved communications with TVA River Operations, have enhanced the licensee's ability to predict these conditions in the future. Therefore, this downpower does not count against the performance indicator.

ID 450

Posting Date 05/14/2008

Question On June 30, 2007 during a heavy rain and lightning storm the A Heater Drain Pump (HDP) unexpectedly tripped due to a failure of the associated 4 kV power feeder cables. Power was reduced to less than 50% power. Based on an engineering evaluation, it was determined that a lightning strike caused an over-voltage condition that damaged the insulation on the A HDP supply feeder cables resulting in an over-current fault, which tripped the HDP.

A review of plant records did not identify previous weather-related failures of the 4 kV feeder cables. Therefore, a failure of the associated 4 kV feeder cables due to a lightning strike, and consequent failure of the HDP, is considered unanticipated and is not mitigated by plant procedures or modifications.

Response The downpower was caused by environmental conditions beyond the control of the licensee, which could not be predicted greater than 72 hours in advance, and could not have been mitigated by a proactive procedure. Therefore, this unplanned power change does not count.

ID 449

Posting Date 05/14/2008

Question During the winter storm cycle, each storm event is evaluated by Diablo Canyon Power Plant (DCPP) staff for its potential impact on power operations. Based on plant policy and procedures, anticipatory power reductions are imposed where marine and/or biological intrusion is predicted at levels that could result in the need to secure a circulating water pump to protect plant systems, such as the intake traveling screens, from damage. However storm predictions may not result in a decision to initiate a unit power reduction in advance of the storm peak. Based on the uncertainty regarding the magnitude of expected marine/biological intrusion, plant procedures also call for the monitoring and trending of main condenser differential pressure. If a maximum threshold is reached, plant procedures direct a power reduction to address the marine/biological intrusion.

On January 03, 2008, the DCPP Operations Manager held an operational decision making meeting (ODM) to discuss a Pacific storm front that was anticipated to move through the power plant general area. Environmental Operations Department and Plant Operations determined that although the magnitude of this storm front was significant, coastal kelp loading would not be an impact to plant operations. Previous storm fronts had removed much of the kelp loading in the coastal region around Diablo Canyon. The conclusion reached in this meeting was that the predicted magnitude of the storm, combined with the available marine/biological debris, was not sufficient to challenge the structural integrity or debris mitigation capability of the traveling screens. As a result, an anticipatory reduction in power was not initiated. On January 05, 2008, as the storm front began moving through DCPP, a second ODM was held to confirm the previous decision to continue full operation of both DCPP units.

As the storm surge came through the DCPP general area on January 05, 2008, DCPP Unit 1 conducted a planned and controlled power reduction of greater than 20 percent in response to storm-induced marine/biological intrusion into the main condenser water boxes. As the storm progressed, its magnitude intensified, exceeding the predicted peak level. The resulting carryover of marine/biological debris caused the main condenser differential pressure to ramp up. As directed by plant procedures, operators initiated a controlled power reduction (to 55%) when main condenser differential pressure exceeded the prescribed value.

PG&E has taken all reasonable actions to proactively assess the effect of Pacific storms on DCPP and has programs/procedures in place to take appropriate actions to both protect plant equipment and to minimize the impact on plant operation. In addition, intake bar racks, seawater traveling screens, circulating water pumps, and main condensers are properly maintained to ensure that they are in a state of readiness to respond to storm conditions. In this case, the storm reached a magnitude that was significantly higher than predicted and resulted in the need to implement a controlled power reduction in response to a monitored plant parameter. Thus, the reporting of this power reduction as resulting from a storm-induced marine/biological debris intrusion satisfies the exclusion for reporting under PI IE03 "Unplanned Power Changes per 7000 Critical Hours."

Response The downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to predict and address this expected condition; however, the magnitude of the marine/biological intrusion changed rapidly and defied predictions. The licensee had taken all reasonable actions to proactively prevent the downpower, and all equipment was maintained and operational. Therefore, this downpower does not count against the performance indicator.

ID 448

Posting Date 05/14/2008

Question During the period of April 14, 2007 and April 16, 2007, the east coast mid-Atlantic Region experienced a Noreaster storm causing high winds and rain in the Delaware River Basin. The unusual wind direction combined with flooding conditions in New Jersey, Pennsylvania and Delaware as well as several unknown flood control dam releases up river led to excessive marine debris in the Delaware River watershed. During the two weeks following the Noreaster storm, increased river flows were experienced, on April 21, 2007 and April 27, 2007 river flows measured at Trenton, NJ were 2 to 3 times higher than the median flow for this date range. This increased river flow tends to entrain more debris than normal at the intake structure. The grassing levels experienced in April 2007 exceeded the weekly average detritus densities experienced in 2005 (which was the previously recorded worst year ever) by approximately 33% and were the highest levels ever recorded by the station. The general make up of the debris was similar to 2005 except there was a higher concentration of trash in the 2007 debris which tends to have a greater effect on traveling screen and water box clogging.

During this period of time, Salem Generating Station was already in Action Level II of the established procedures for Grassing*. (See Attachment 1 for further discussion of the established procedure guidance). Sampling of the river for detritus was increased to a daily frequency on April 21, 2007 from the normal 3 days a week. Samples are taken continuously throughout the day to assess the immediate detritus concentration and determine the daily average and weekly average which is used in the Salem Circulating Water System Risk Snapshot. Based on the increased detritus level measurements/predictions, Operators entered the applicable procedures that directed increased inspections of the circulating water intake structure to ensure equipment is working properly. During the period of April 23, 2007 to May 3, 2007, circulating water risk snapshots (see Attachment 1 for further discussion) were increased to twice a day to set the priorities for maintenance to maintain the reliability of the circulating water system during the heavy grassing period. Although the time period during the year for grassing impact is known and procedures for monitoring grassing levels are in place, there are no accurate prediction methods that can determine the actual grassing impact at the Circulating Water intake structure greater than 72 hours in advance.

On April 20, 2007 Salem Unit 1 began its return to power from its 18th refueling outage. During the power ascension, circulating water pumps were being removed from service in accordance with procedures to clear the traveling water screens and to clean the condenser water boxes of debris. On April 22, 2007 a power level of 80% was reached. A greater than anticipated influx of marine debris/grassing occurred causing circulating water pumps to be shutdown. The delta temperatures across the condenser began to increase and power was reduced to approximately 40% power in accordance with abnormal operating procedures to maintain condenser outlet temperatures below established limits. When monitoring and predictions indicated a reduced grass level, power was increased to 48% on April 23, 2007 where it remained for approximately one day for continued monitoring of grassing levels. On April 24, 2007 grass levels increased again requiring a downpower to 40%. Late on April 24, 2007 Salem Unit 1 was manually tripped by procedure due to the tripping of several circulating water pumps as a result of an influx of marine debris/grassing. [This was counted as a reactor shutdown] (See Attachment 2 for Power-History curve)

The unit returned on April 26, 2007 while management monitored and trended the marine debris/grassing concentration levels. Salem Station was still in an elevated Action Level II condition due to elevated marine debris/grassing; however, the marine debris/grassing daily mean level began to decrease.

On April 27, 2007, Salem Unit 1 had achieved 74% power when a reduction in power to 40% was performed in accordance with procedures. An influx of marine debris/grassing led to the tripping of several circulating water pumps in accordance with procedures. The power remained at 40% until river conditions permitted return of equipment to service to allow for power ascension. The power ascension was based on actual river data parameter trend analysis of marine debris. On April 29, 2007 power was increased to 80% power. Power ascension was held at 80% for fuel conditioning requirements and would not be increased above 80% until a continued evaluation of marine debris/grassing levels occurred. On April 30, 2007 river marine debris/grassing levels unexpectedly increased. The onset of the volume of marine debris/grassing was not within the predicted, monitored and trended parameters of the river. The condition required tripping of four of six circulating water pumps and the reactor was tripped in accordance with the abnormal operating procedures. [This was counted as a reactor shutdown] The marine debris was only visible by screen loading at the time of the event.

The station has taken numerous reasonable steps to increase unit reliability over the past years by modifications to improve the circulating water intake performance, which has proved successful in coping with record marine debris/grassing season in 2005. The station has recently implemented and tested a new traveling water traveling screen.

In addition, following the April 2007 down powers and unit trips a root cause evaluation was performed with a corrective action to determine if any further actions could be done to minimize the impact of grassing on the Unit operation. This action has determined that throttling of the circulating water flow to reduce the impingement of grass on the circulating water traveling screens may help prevent future plant trips; however, these actions would not avoid the unanticipated down powers. Additional river grassing predictions were reassessed during the root cause evaluation but no actions were identified that would be able to reliably predict increased grassing levels 72 hours in advance.

Given that the circumstances of this marine debris intrusion were beyond the control of the plant, and that appropriate site actions are proceduralized, can the April 22, 2007 and April 27, 2007 down power events be exempted from counting as an unplanned power change? Based on the information provided, it is recommended that the April 22, 2007 and April 27, 2007 down powers not be counted since the magnitude of the onset of marine debris could not have been predicted 72 hours in advance.

*Note: The term grassing or grass as used in this FAQ is marine debris that is in the form of reeds

(Phragmites), detritus (decaying organic matter from marsh bottoms), hydroids, leaves, and trash.

Response The downpowers were caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to address this expected condition; however, the magnitudes of the grassing events were unique in severity. The licensee had taken all reasonable actions to proactively prevent the downpower, and all equipment was maintained and operational. Therefore, these downpowers do not count against the performance indicator.

ID 447

Posting Date 05/14/2008

Question A High Pressure Coolant Injection (HPCI) steam supply valve, located in the drywell, tripped during motor-operated valve surveillance testing. The trip occurred at 0500 on 9-4-07. Subsequent troubleshooting led to the decision to perform a shutdown to repair the valve. This decision was made @ 2300 on 9-4-07. The unit power was reduced 20% @ 2130 on 9-7-07.

If the 72-hour clock starts at 0500 on 9-4-07, when the valve trip occurred, then the power change is classified as planned. If the 72-hour clock starts at 2300 on 9-4-07, when the decision was made to perform the power change to support the valve repair, then the power change is classified as unplanned.

Response The licensee created a troubleshooting plan to assess the impact of the failed valve. One option on this plan, when implemented, would have involved a plant downpower and shutdown. The time between the creation of the troubleshooting plan which recognized the potential need to shutdown and performance of the downpower was greater than 72 hours. Therefore, the downpower does not count against the performance indicator.

ID 445

Posting Date 04/16/2008

Question At FitzPatrick, intrusion of Algae (Cladophora and other types of algae vegetation) at the circulating water intake structure has occurred several times and caused Traveling Water Screen (TWS) blockage. Traveling screen blockage has lead to failure of a traveling screen. This has cascaded to multiple screen failures which can cause a loss of the Circulating Water System and loss of inlet cooling water for the plant which can cause loss of the main condenser (Ultimate Heat Sink). Because of these events, Fitzpatrick has responded by performing several down powers in order to take a circulating water pump(s) off line to reduce water velocity and thus algae adherence to the TWS.

Contributing factors to these events are high winds out of the Northwest, cladophora/algae in the lake, the orientation of the submerged intake structure, and the large volume of water drawn through the intake canal by three CW pumps.

Over the last few months, FitzPatrick has taken significant steps, including changes in operating strategy and procedures, as well as equipment enhancements to reduce vulnerability of the plant to this phenomenon. FitzPatrick has also taken steps to minimize clodophora through use of divers harvesting the algae in areas of high concentration.

This FAQ is intended to apply to the November 16, 2007 event and future downpowers related to these conditions. On 11/16/07, a plant down power was initiated from 100% power due to an intrusion of Cladophora Algae. This event was similar to events that have occurred on September 12, 2007, October 13, 2007, and October 28, 2007 in that the influx of algae resulted in the operations staff lowering power (i.e., shutdown or down power) to ensure adequate inlet cooling water for the plant. Since the Root cause evaluation had not been completed for the September 12th event, all of the long term corrective actions had not been implemented for the November 16th event. However, interim corrective actions documented in Operations Shift Standing Order (OSSO) 2007-020 Revision 2 were in place at the time of the November event. Below is a complete list of actions in place as of the date of this FAQ:

Equipment Upgrades:

- Installed higher strength shear pins.
- Installed downstream screen guide rails to prevent contact with screen house floor
- Installed larger motor on screen drive train which results in higher speed operation
- Eliminated fluid coupling from the drive train

- Installed screen wash diversion troughs
- Installed larger ports in screen housings and staged fire hoses

Procedure Changes and Detection/Mitigation Strategies:

- Lowered setpoint for screen differential pressure alarm
- Added steps to OP-4 for two screen wash pump operation
- Added guidance for use of fire system sprays on screens
- Installed web cam at fish basket
- Trained operators on shear pin installation
- Staged tools, shear pins and tag out locks
- Provided additional guidance for power reduction based on weather forecast
- Set up a call-out page for intake problems

Additional Procedural Guidance Provided for Power Reduction Based on Weather Forecast:

Trigger Point # 1 from Operational Procedure:

1. **IF** severe weather, sustained winds **GREATER THAN** 20 mph, or other conditions that could cause a rise in the amount of debris in intake water, exist or are expected.

Actions if Trigger Point # 1 is exceeded:

IF Trigger 1 is exceeded **THEN** perform OP-4 Section E.2.2. This procedure section will perform the following actions:

- Place traveling screens in continuous mode per Subsection G.15 to determine amount of incoming debris.
- Frequently monitor traveling screen performance and debris basket quantity.
- **IF** significant lake debris is incoming, **THEN** continuously monitor screen performance, debris basket quantity and screen differential level.
- Commence screen wash two pump operation per Section G.29
- **IF** any indication of rising screen d/P, **THEN** perform the following:
    - Direct control room to start Fire Pump.
    - Initiate cleaning using fire hoses.

Trigger Point # 2 from Operational Procedure:

2. **IF** the following combination of wind direction and wind speed, as measured with on-site instrumentation, is met:

   Wind Direction from 240º (WSW) through 030º (NNE)

   AND

   15 minute average wind speed is greater than 30 mph

   AND

Evidence of debris intrusion as determined by the Shift Manager using the following criteria:

- Service Water Strainer Differential Pressure Alarms
- Rising Traveling Screen Differential Level
- Screenwash booster pumps with (mitigating actions of fire hose spray) are not effective in removing debris from screens. Indications of this would be an increasing amount of carry over on south side of screens.
- Frequent fish basket change out is required OR if there is degradation in the methods or ability to remove incoming debris. Examples would be:
    - Malfunction of screenwell crane
    - Resources not available
    - Screen wash system degradation

Actions if Trigger Point # 2 is exceeded:

IF Trigger 2 is exceeded **THEN**

- Reduce power per OP-65 and remove C Circulating Water Pump. Power reduction at normal limit of 200 MWth/ minute is warranted.
- Contact WWM to verify Risk assessment
- Initiate Traveling Screen Issue Report to Plant pager message located on the Emergency Planning Department website.
- Initiate Traveling Water Screen Monitoring Plan located at M:\PLANNING\FO183\Engineering\CWS and Trav Screen Monitoring Rev 2.doc.
- Review and Brief AOP-56 (High Traveling Screen or Trash Rack Differential Level)

In summary, JAF believes that the shutdowns and down powers were caused by an environmental problem that is a new phenomenon not previously experienced in terms of severity, that it could not have been predicted greater than 72 hours in advance, that compensatory measures have been put in place. Based on the corrective actions taken and subsequent proactive measures taken by the licensee, future down powers should not count as an unplanned power change for future performance indicators.

As noted above, NEI 99-02 Revision 5, in discussing downpowers that are initiated in response to environmental conditions states The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP? Yes, the transient meets the conditions for an environmental exception and should not count against the performance indicator.

Response The downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to address this expected condition; however, the magnitude of the algae intrusion was unique in severity. Until the Travelling Water Screen improvements are complete, additional downpowers due to algae intrusions of this magnitude will not be counted as long as proactive procedures to lessen the severity of the event have been implemented by the licensee. After the Travelling Water Screen improvements are complete, algae intrusions of this severity will no longer be considered unique for the purpose of this performance indicator and they may be counted.

ID 444

Posting Date 04/16/2008

Question On October 13, 2007 a plant shutdown was initiated from 100% power due to an intrusion of Cladophora Algae. This event was similar to the event on September 12, 2007 that resulted in the insertion of a manual scram. Since the Root cause evaluation had not been completed on the September event, long term corrective actions had not been implemented, however, interim corrective actions documented in Operations Shift Standing Order (OSSO) 2007-020 were in place at the time of the October event.

Interim corrective actions included the following:

Monitoring Requirements:

Control Room:

- Trend Screenwell level on EPIC Log 1 or the 1PLOTC EPIC trend plot.
- Monitor Traveling Screen Differential Level (36DPI-111) and Trash Rack Differential Level (36DPI-112) frequently.
- Monitor B2 Condenser water box differential pressure (36DPI-101B2) frequently.
- Monitor Condenser Water Box differential temperatures.
- Monitor RHRSW and ESW pump flow rate for degradation when in service.

In Plant:

- When the Traveling Screens are in continuous mode inspect Traveling Screen performance locally every 2 hours.
- Monitor Normal Service Water pump strainer differential pressure every 4 hours when associated pump is in operation. (46DPS-131A & 46DPS-131B alarm at 5 psid. 46DPS-131C alarms at 7 psid.)
- Monitor RHRSW and ESW discharge strainer dP once per hour when these pumps are in service.

Contingency Actions:

- Fire hose station is available for traveling screen manual cleaning.
- Maintain the debris basket clean of accumulated debris.
- Ensure a spare debris basket is available.

Other Conditions and Actions:

High Wind Conditions (sustained > 20 mph @ 30 ft.):

- Ensure all three Traveling Screens are in the continuous run mode.
- Monitor traveling screen performance and debris basket quantity every 30 minutes.
- If significant lake debris is incoming, continuously monitor traveling screen performance, debris basket quantity, and intake level.

Indication of Degraded Traveling Screen Performance:

- With the screens rotating and indication of rising screen dP, initiate manual cleaning using fire hoses. Remove access panels as required.
- Closely monitor Traveling Screen differential pressure.
- Enter AOP-56 (High Traveling Screen and Trash Rack Differential Level) and monitor rate of change.

Indication of Lowering Screenwell Intake Level (>0.3 feet):

- With any indication of lowering lake level, enter AOP-64 (Loss of Intake Water Level)

- Closely monitor rate of change of Screenwell intake level for determining mitigating actions.

Receipt of Service Water Pump Strainer dP Alarms:

- Execute ARP-09-6-2-33 (SERV WTR PMP STRAINER DIFF PRESS HI).
- Ensure applicable strainer is rotating and flush valve is full open.
- Place all operating Service Water Pump strainers in manual backwash until dP is less than 5 psid.
- Inspect Screenwell intake for debris and ensure Traveling Screens are in continuous mode until it is confirmed that there is no debris input from the lake.

Actions for a Main Circulating Pump Start:

- Ensure all Traveling Screens are in continuous mode.
- Do not start additional Main Circulating pumps unless Traveling screen dP is less than 2H2O.
- Monitor condenser water box differential pressure and temperatures for the subsequent hour.
- Monitor Screenwell intake level for unexpected level change.

Actions during Emergency Service Water and RHRSW Pump Operation:

- When RHRSW pumps are initially started, monitor strainer dP and motor cooling flow for the first 15 minutes. Then monitor strainer dP hourly for the next eight hours of pump operation to determine if a degrading trend exists. After 8 hours, monitor every 4 hours. (10DPIS-277A/B alarm at 7 psid)
- When ESW pumps are initially started, monitor strainer dP and motor cooling flow for the first 15 minutes. Then monitor strainer dP hourly for the next eight hours of pump operation to determine if a degrading trend exists. After 8 hours, monitor every 4 hours. (46DPS-132A/B alarm at 4.0 psid)
- Monitor RHRSW and ESW pump flow rate for degradation on EPIC when pumps are operating.

On October 13, 2007during a high wind event these actions were implemented but were inadequate to prevent clogging of the traveling water screens (TWS). Once clogged the TWS motors were unable to maintain continuous operation. The increasing differential pressure resulted in the TWS shear pins shearing off to protect the TWS motors. Once the TWS became stationary the continuing suction from the plant circulating water (CW) pumps resulted in further plugging of the TWS such that the only means available to maintain the Ultimate Heat Sink (UHS) level was to reduce power and secure CW pumps. UHS level was seen to increase as circulating water pumps were secured.

Once the TWS were clogged and stopped the only means to lower the differential pressure across the TWS and allow movement of the TWS was to take the plant to cold shutdown and secure all CW pumps. By securing the suction from the back side of the screen the TWS motors were able to lift the TWS clear of the water so that they could be cleaned.

Until the debris loading reached the point that the TWS differential pressure exceeded 12 inches WC the cleaning efforts were successful in removing the cladophora. However, once the debris loading reached the point where differential pressure reached 12 inches WC the TWS motors were no longer able to lift the loaded screens out of the water so that they could be cleaned.

Contributing factors to this event are high winds out the Northwest, large volumes of cladophora algae in the lake, the orientation of the submerged intake structure, the large volume of water drawn through the intake canal by three CW pumps. Preliminary evaluation results indicate that with the current design of the TWS system the only means to mitigate this environmental condition is to reduce power so that one or more CW pumps may be secured thereby reducing the rate of influx. Since these conditions can not be predicted greater than 72 hours in advance and the only effective means to mitigate the influx is to reduce power the actions taken were the correct actions.

In summary, JAF believes that the shutdown on October 13, 2007 was caused by an environmental problem that is a new phenomenon not previously experienced at JAF in terms of severity, that it could not have been predicted greater than 72 hours in advance, that interim compensatory measures put in place after the September 12, 2007 scram pending completion of the root cause evaluation were reasonable and while they did not prevent recurrence they did lessen the impact of the event in that they allowed the operations department to take prompt proactive actions to perform a unit shutdown in lieu of a scram. Based on the initial interim corrective actions and subsequent proactive measures taken by the licensee the unit shutdown should not count as an unplanned power change on the October performance indicator.

As noted above NEI 99-02 Revision 5, in discussing downpowers that are initiated in response to environmental conditions states The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP? Yes, the transient meets the conditions for an environmental exception and should not count against the performance indicator.

Response The downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to address this expected condition; however, the magnitude of the algae intrusion was unique in severity. Until the Travelling Water Screen improvements are complete, additional downpowers due to algae intrusions of this magnitude will not be counted as long as proactive procedures to lessen the severity of the event have been implemented by the licensee. After the Travelling Water Screen improvements are complete, algae intrusions of this severity will no longer be considered unique for the purpose of this performance indicator and they may be counted.

ID 437

Posting Date 12/05/2007

Question NEI 99-02 Revision 5, discusses downpowers that are initiated in response to environmental conditions states The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP? Yes, the transient meets the conditions for an environmental exception and should not count against the performance indicator.

Response The rapid increase of 13 degrees F in three hours in the B condenser had never before been experienced by the utility. The following day, April 2, there were indications of condense fouling, most likely caused by marine debris. On April 2 the licensee conducted a downpower of 25%. That downpower was caused by an environmental problem that could not have been predicated greater than 72 hours in advance and therefore does not count in the Unplanned Power Changes PI. However, should these same conditions recur, the licensee is expected to have in place the necessary practice, procedures, staff, and equipment to handle the conditions such that a downpower of greater than 20 percent may not be necessary. Development and use of such a procedure in the future, may provide a basis for a future FAQ allowing excluding a downpower >20% for this PI.

Mitigating Systems

MS06 MSPI Emergency AC Power Systems

ID 458

Posting Date 07/16/2008

Question The NEI ROP Task Force and the NRC staff have, in the past, spent significant time reviewing FAQs and dealing with the term independent of the maintenance performed. The conduct of maintenance activities involves numerous support activities. It is recognized that during the conduct of a specified maintenance activity the potential exists to inadvertently induce equipment failures that would not be immediately identified or recognized. Such failures would be dependent on the maintenance activity, that is the failure would not have occurred if the maintenance had not been performed, and most likely would be identified during PMT performed prior to restoring the component to operable status. Failures that are caused by the maintenance activity should not be counted as they are not indicative of the reliability of the equipment that was undergoing maintenance. Licensee utilize PMT to verify that a monitored component is operable prior to returning it to service after the completion of a maintenance activity. The following guidance was developed by the NEI ROP and the NRC staff to make it easier to determine what failures, identified during PMT, are dependent on the maintenance performed and which are independent of the maintenance performed.

Response Page F-26, line 34 - The following test should be inserted in NEI 99-02, Rev. 5 at line 34 on page F-26.

<u>Treatment of failures discovered during post maintenance tests:</u>

Failures identified during post-maintenance tests (PMT) are not counted unless the cause of the failure was independent of the maintenance performed. The maintenance scope of work includes the activities required to be performed to conduct the maintenance, including support activities, the actual maintenance activities, and the activities required for restoration of the monitored component(s) to their available and operable conditions. This includes, but is not limited to, typical tasks such as scaffolding erection and removal, coatings applications, insulation removal and installation, rigging activities, health physics activities, interference removal and restoration, as required to support and perform the required maintenance activity. Support activities may be planned, scheduled and implemented on separate work orders from the work order for the monitored component(s). System or component failures introduced during the scope of work are not indicative of the reliability of the equipment, since they would not have occurred had the maintenance activity not been performed. In addition, the potential exists that components or devices not included in the direct scope of work may be affected by the ongoing activities. Such failures are not counted providing:

- They are identified during or prior to the post-maintenance testing and are corrected prior to the component(s) being returned to operable status,
- The repair is documented in a work package, and
- The critical components not directly in the scope of work, but that have the potential to be affected by the maintenance activity, are noted by means such as cautions in the procedures, inclusion in the pre-job briefings, protection by signs, placards or padding.
- The licensee uses the corrective action program to document the basis for the determination that the cause of the failure was dependent on the maintenance performed. This determination must establish a clear relationship between the maintenance performed and the failure.

ID 454

Posting Date 05/14/2008

Question NEI 99-02 page F 21, lines 24 through 27 states *Run hours (pumps and emergency power generators only) are defined as the time the component is operating. Run hours include the first hour of operation of the component. Exclude post maintenance test run hours, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case, the run hours may be counted as well as the failure.*

The guidance currently does not specify how pump operational run hours should be counted when run as a continuation of post maintenance testing. Even though there will be no associated demand corresponding with these hours, they should be counted as run hours from the time the pump is declared operable.

Response Append the guidance as follows:

Run hours (pumps and emergency power generators only) are defined as the time the component is operating. Run hours include the first hour of operation of the component. Exclude post maintenance test run hours, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case, the run hours may be counted as well as the failure. Pumps that remain running for operational reasons following the completion of post maintenance testing accrue run hours from the time the pump was declared operable.

ID 446

Posting Date 04/16/2008

Question During NRC review of MSPI data, the reviewer questioned the reporting of unavailability and failures under certain circumstances. The example in question stems from a failure of a pressure switch on the Unit 1B Emergency Diesel Generator (EDG) that resulted in a "Turbo Thrust Bearing Failure" alarm. The diesel subsequently tripped during its cool down cycle. It was determined the DG would perform its emergency function, but would not operate in test mode. The plant did not count any unavailability for this test mode failure because the DG was able to perform its emergency function.

At Byron, there are two EDGs per unit. Under MSPI, all four EDGs are monitored for each unit due to the potential alignment of the Component Cooling Water System that may require the EDGs for the opposite unit to provide power to the CC and SX pumps. (ref. Section 2.4 of the Byron Station MSPI Basis Document.) To clarify this statement, it should be noted that the common component cooling water heat exchanger can be mechanically aligned to either unit. Depending on the alignment, one units component cooling water and essential service water pumps will be providing cooling to the opposite unit. The common component cooling water pump can be powered from either units ESF bus. Two component cooling water and two essential service water pumps are powered from each unit. Thus, in a loss of power on one unit, an opposite units ESF Bus may be powering a component cooling water or essential service water pump on the unit that did not lose off-site power to provide cooling to the unit that did lose offsite power. For a dual unit loss of offsite power, the opposite units EDG may be providing power through the ESF Bus to the component cooling water or essential service water pump to provide cooling to the opposite unit.

The NRC reviewer noted that a bus undervoltage on one unit does not provide an emergency start signal to the diesels on the other unit. The DG would need to be started manually (test mode). The reviewer questioned how an EDG with a test mode failure could supply power to the CC or SX pump that is mechanically aligned to the opposite unit, and whether this constitutes a EDG failure counted against the opposite unit. Also, should the diesel accrue unavailability for the opposite unit, and would this unavailability be unplanned?

Byron Station Response

The function of the EDG is to supply power to the ESF bus in event of a loss of off site power to that bus. Though plant design allows an EDG from one unit to be crosstied to supply power to the other unit, this function is NOT an MSPI monitored function. Only the crosstie breakers are monitored in MSPI for this function in accordance with NEI 99-02 F.1.1.1 and F.2.1.1. The opposite unit EDGs are only included in the scope of MSPI as they may be required to provide power to that units component cooling water and essential service water pumps following a loss of offsite power to that unit. As the MSPI function of the emergency AC power system is the ability of the emergency generators to provide AC power to the class 1E buses following a loss of off-site power, any time an EDG is performing this function, whether to support its own unit or cooling loads to the opposite units A RH Train, it is due to a loss of offsite power to the associated ESF bus. In this case, the EDG would receive an autostart signal which would not be affected by the inability to start the EDG in the test mode. Therefore, this event should not be considered a failure, nor should unavailability be accrued.

In accordance with the MSPI guidance, the MSPI scoping does not include the opposite unit EDGs for their electrical cross-tie capability. The cross-tie breakers are included in the MSPI scope and this ensures that unit electrical cross-tie capability is available under all conditions as illustrated in the following example.

Example Unit 1A DG has a fault that prevents it from operating correctly in test mode, although it will operate correctly in emergency mode.

Scenario 1 - A loss of offsite power (LOOP) occurs on Unit 2 only, but the 2A DG fails to start. Unit 1 can energize the ESF bus through the crosstie, as the PRA has credited. Since Unit 1 has not lost off-site power, the Unit 1 ESF bus remains energized by offsite power through the Station Auxiliary Transformer (SAT) and is capable of energizing the Unit 2 ESF bus through the crosstie.

Scenario 2- A LOOP occurs on both units and the 2A DG fails to start. The ESF bus can still be energized through the crosstie. Since Unit 1 has also lost power, the 1A DG will now be running in emergency due to the bus undervoltage on its own unit. With the diesel operating in emergency mode, any test mode fault will not be an issue. The 1A DG will be able to power the Unit 2 ESF bus through the crosstie as designed. The 1A and 1B DG have adequate capacity to supply the Unit 1 emergency loads and the required Unit 2 loads through the cross-tie.

Per NEI 99-02 guidance, an EDG is not considered to have failed due to a spurious operation of a trip that would have been bypassed in a loss of offsite power event (emergency mode).

Also per NEI 99-02, unavailability is counted when the system is unavailable to perform its monitored functions. The Byron bases document states the function monitored for the emergency AC power system is the ability of the emergency diesel generators (EDGs) to provide AC power to the class 1E buses upon a loss of off-site power while the reactor is critical

Therefore, since the diesels would only be called upon to supply the opposite units ESF bus in emergency mode, any test mode problem that is not a failure on its own unit should be considered neither a failure nor unavailable on the other unit.

Response The EDG should not be considered unavailable in this situation.

The design basis function of Unit A EDGs supplying loads to the opposite unit, is not an EAC MSPI monitored function. EDGs that can supply loads to both units during certain accident scenarios are still monitored by MSPI with respect to their assigned train/unit status (i.e., normally aligned unit.) For example, for a two unit site with 4 EDGs, Unit 1 will have two assigned EDGs (Unit 1 EDG-A and Unit 1 EDG-B) and Unit 2 will have assigned 2 EDGs (Unit 2 EDG-A, Unit 2 EDG-B). The boundary that separates these 4 EDGs is the unit cross-tie breakers (see NEI 99-02, Rev 5, App F, page F-2, Unit Cross-Tie Capability).

Test-mode failures of any EDG is counted as a failure, IF the licensee maintained the EDG in an "available" status, and where the failure rendered the EDG from auto-starting in emergency mode regardless of whether it would supply the ESF bus in either unit. However, if the emergency mode start feature was unaffected by the test mode failure, and the EDG would perform its PRA monitored function on the assigned unit, then no failure occurred with respect to MSPI unreliability monitoring. Additionally, unavailability on the other MSPI systems would need to be evaluated with respect to how the test mode failure affected their status.

ID 441

Posting Date 03/19/2008

Question It is possible that the risk significance driven from system unreliability can be over stated in MSPI. Specifically, the difference in using Option 1 versus Option 2 of NEI 99-02 Section F.2.3.3 can result in conservative failure values for risk sensitive systems being used which produce an outcome that can deviate up to two orders of magnitude.

Section F3 of NEI 99-02 Rev. 5 notes that it is not appropriate that a system should be placed in a *white* performance band due to expected variation in measured performance. This problem is most noticeable for risk sensitive systems that have few demands in the three year monitoring period. A relatively low risk significant incremental failure may result in a change from a very low safety significance performance band to the substantial safety significance performance band. This results because the limit of 5.0E-07 applicable to the most significant failure is not applied where the calculated MSPI value is greater than 1.0E-05. This result is contrary to the intent and stated purpose of section F3: A MSPI> 1.0E-06 will still be a possible result *if there is significant unavailability, or failures in other components in the system.*

NEI 99-02 Section F 2.3.3 Option 1 applies a set of maximum values for all failure modes and Option 2 assigns a separate ratio for each specific failure mode. Application of the risk significance multiplier specifically applicable for each failure mode more accurately models the risk contribution of the failure modes and better implements the intent of NEI 99-02.

NEI 99-02 does not contain any specific guidance that precludes switching between Options 1 and 2 of Section F 2.3.3. Switching from Option 1 to Option 2 of NEI 99-02 Section F 2.3.3 is not a change in non-PRA information as discussed in FAQ 432 (below) since the specific failure mode values are coefficients contained in the PRA. Selecting either Option 1 or Option 2 is a matter of implementing the already approved methods defined in NEI 99-02. If the specific failure mode values for a system are listed in the MSPI basis document in effect at the start of a quarter then a plant should be allowed to report their quarterly data with either Option 1 or Option 2 provided the change in option is documented in the quarterly submittal and the basis document is subsequently updated to reflect which Option was utilized.

Question:

Can a plant change from NEI 99-02 Section F 2.3.3 Option 1 to Option 2 in the current quarter if this change is not the result of a revision to the PRA and the specific values were contained in the MSPI basis document? Currently, there is no specific guidance in NEI 99-02 that precludes changing between the documented options.

Response Any change to the MSPI Consolidated Data Entry (CDE) coefficients, which includes changes resulting from PRA updates, discovered CDE input errors, and PRA modeling revisions, will not take effect in the quarter that they are made. This understanding is consistent with NEI 99-02, Section 2.2 that emphasizes any PRA model changes that impact MSPI input values (CDE coefficients) will take effect the following quarter in which they are made. It should be noted that it is impractical to list every possible way that CDE input values can change. Changing from Option 1 to Option 2 on calculation of the [FV/UR] Max used by the MSPI algorithm is a change in the PRA input in the calculation of the CDE input values. Therefore, it is considered a change in use of PRA values used by CDE and the change can only take effect in the next quarter.

This position is also consistent with FAQ 432 which stated that for changes to PRA coefficients will be used in the MPSI calculation the quarter following the approved PRA update; and that changes to non-PRA information will become effective in the quarter following an approved revision to the site MSPI basis document.

If appropriate provide proposed rewording of guidance for inclusion in next revision.

However, changes to the basis document that do not affect specific PRA values are permitted and can be updated in CDE at any time.

ID 429

Posting Date 09/19/2007

Question Is it acceptable to use the segment approach as described in NEI 99-02, Revision 5, Appendix F, page F-3, line 40, for the Oconee Emergency AC Power System to change from two trains to four segments?

Is it acceptable to use plant specific Maintenance Rule data from 2002-2004 to calculate the Unplanned Unavailability Baseline for the Oconee Emergency AC Power System? Oconee is requesting to use the same approach as the Cooling Water Systems, as described in NEI 99-02, Appendix F, page F-10, line 13.

NEI 99-02, Revision 5, Appendix F, page F-3, line 12 states, For emergency AC power systems the number of trains is the number of class 1E emergency (diesel, gas turbine, or hydroelectric) generators at the station that are installed to power shutdown loads in the event of a loss of off-site power.

NEI 99-02, Revision 5, Appendix F, page F-10, line 5 through 11 states, If a front line system is divided into segments rather than trains, the following approach is followed for determining the generic unplanned unavailability:

1. Determine the number of trains used for SSU unavailability reporting that was in use prior to MSPI.

2. Multiply the appropriate value from Table 1 by the number of trains determined in (1).

3. Take the result and distribute it among the MSPI segments, such that the sum is equal to (2) for the whole

MSPI system.

Table 1 of Appendix F details the Unplanned Unavailability Baseline data based on ROP industry-wide data. To accurately reflect unplanned unavailability of the Oconee Emergency AC Power System, the plant specific data should be used to determine a baseline.

In the original MSPI Basis Document, the Oconee Emergency AC Power System was identified as two independent, separate trains. This was a simplified, conservative categorization that was chosen to meet the guidance per Appendix F, Page F-3, line 12 for Emergency AC Power Systems.

The Oconee Emergency AC Power System is unique in that it is a hydroelectric system, significantly different in design from other plants which use diesel generators as the Emergency AC Power. Keowee Hydro Station consists of two hydroelectric units which connect to all three Oconee Units. These hydro units are connected to each Oconee unit through an overhead power path as well as through an underground power path. The Keowee units are interchangeable and can supply either path, which differs from a normal diesel generator train lineup. This unique arrangement of Keowee (i.e. two independent power paths with two interchangeable power sources) requires the use of a segment approach (as opposed to the two-train approach) to accurately reflect the risk profile of the Emergency Power System. Currently, the base PRA model for the Oconee Emergency Power system accounts for the different segments; therefore, no changes need to be made to the base PRA model to incorporate this change.

Redefining the Emergency AC Power System into segments, using the same approach as described for Cooling Water Systems, will more accurately reflect the risk profile of the Oconee Emergency AC Power System.

The Unplanned Unavailability Baseline for Emergency AC Power using 2002-2004 Maintenance Rule data for the segment approach is comparable to the Unplanned Unavailability Baseline of the diesels, with the new Oconee Emergency AC Power baseline being slightly more conservative than that of the diesel baseline when using the segment approach.

Oconee Technical Specifications allow both emergency power supplies (Keowee Hydro Unit 1 and 2) to be out of service concurrently, i.e. a "dual unit outage," for up to 60 hours for planned maintenance, a feature unique to Oconee. Also, per Technical Specifications, the planned removal of both emergency power sources is contingent on having the standby buses energized from Lee combustion turbines through a dedicated power path. This configuration is explicitly modeled in the Oconee PRA for planned dual-unit outages.

The planned unavailability baseline for Emergency AC power includes hours for the planned dual-unit outages which occur on a regular cycle. Any additional planned dual-unit outages necessary to fix equipment issues within the current MSPI quarter will not be included in the baseline. Planned unavailable time during dual unit outages is accrued on any train/segment that is affected by the dual unit outage, causing multiple trains/segments to count unavailable time during the dual-unit outage. Oconee's approach for the Emergency AC Power segments uses PRA basic events that do not credit the standby bus being energized (prior to an initiating event) which results in Birnbaum values that are higher than those associated with an actual planned dual-unit outage

Therefore, although the Oconee emergency power system has planned dual-unit outages allowed by its Technical Specifications, the risk profile is conservatively reflected and adequately captured in MSPI due to counting unavailability time on multiple trains/segments and applying higher risk importance values.

The N (Normal) breakers are no longer going to be included as monitored components. Also, the FV/UA max will no longer be the FV associated with the N breakers. These changes are due to the fact that the N breaker itself, as well as a failure of the N breaker, is outside the scope of the NEI guidance for Emergency AC power systems.

Response In order to remove the unnecessary conservatism in the Oconee MSPI model and more accurately depict the Oconee design, Duke proposes to use the four segment approach for the Emergency AC Power System. Each Keowee unit is a segment, and each power path is a segment. The segment approach is described in NEI 99-02, Appendix F, page F-3, line 40, for Cooling Water Systems. Oconee is requesting to use the same approach with its Emergency AC Power System.

Duke also proposes to update Table 1 in NEI 99-02, Appendix F-9, to reflect that the unplanned unavailability baseline data associated with Oconee Emergency AC system is plant specific Maintenance Rule data for 2002-2004, as seen with Cooling Water Systems described in NEI 99-02, Appendix F, page F-10, line 13.

A CDE software change will be implemented for Oconee to support four train data. This entails requantifying past reported data for a 4-train configuration which will be reported with the submittal of 3Q2007 data. In addition, this change involves archiving the current 2-train data for the past reporting quarters until the final CDE software changes are final. Once the software changes and upgrades to CDE are final, the original two train data will be unarchived and CDE will have the capability to switch between two and four train configurations. The final CDE software change is estimated to be completed in 2008.

ID 428

Posting Date 05/18/2007

Question NEI 99-02 Guidance needing interpretation (including page and line citation)

Appendix F, page 20, Section F2.2.2 Failures, lines 35 through 43:

"EDG Failure to start: A failure to start includes those failures up to the point the EDG has achieved required speed and voltage. (Excludes post maintenance tests, unless the cause of failure was independent of the maintenance performed.)"

"EDG Failure to Load/Run: Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform its monitored functions. This failure mode is treated as a demand failure for calculation purposes. (Excludes post maintenance tests, unless the cause of failure was independent of the maintenance performed.)"

Event of circumstances requiring guidance interpretation:

The B emergency diesel generator (EDG) experienced a failure to load / run during Post Maintenance Testing (PMT) following a major maintenance activity on April 4, 2005. The cause of the failure was an out of calibration jacket water temperature switch. Although there was no specific planned maintenance on the jacket water temperature switch, testing of the switch revealed that the most likely cause of the defect was inadvertent impact to the switch by workers or equipment during other planned major maintenance activities that had been performed in the vicinity of the temperature switch. The defect did not exist prior to the maintenance, and was revealed during scheduled PMT prior to the EDG operability run and prior to returning the engine to service following the major inspection activity.

It is FPL Energy Seabrooks position that since test data indicates the cause of the failure was most likely due to an impact on the jacket water temperature switch during maintenance, the failure was not independent of the maintenance activities even though no direct maintenance took place on the switch, was detected and corrected during the PMT activities prior to returning the EDG to service, and therefore can be excluded per the guidance in Appendix F, Section 2.2.2.

Is it appropriate to exclude failures most likely caused by defects introduced directly or indirectly during scheduled maintenance and subsequently identified during PMT and corrected prior to returning the engine to service? If it is appropriate, should this failure be excluded as an MSPI load/run failure?

If Licensee and NRC resident / region do not agree on the facts and circumstances explain:

The NRC Senior Resident has taken the position that the maintenance exclusion described in Appendix F, page F-20, Section F2.2.2 is not applicable to a failure if there was no planned maintenance performed directly on the component that failed.

Response Response Appeal Process
Decision Not To Be Used For Future Reference Or Incorporation Into NEI 99-02.

The failure of the temperature switch that was revealed during the post-maintenance testing is a valid failure that ultimately could have impacted the reliability of the equipment, in that it may have gone undetected while the equipment was in an operable state of readiness. In addition, on-line maintenance testing does not always provide assurance of operational readiness. The key factor in determining the eligibility of the EDG failure described in FAQ 67.3 for exclusion is whether or not the cause for failure is "independent of the maintenance performed." Seabrook representatives acknowledged that the temperature switch, the component which caused the failure, was not part of the "maintenance performed" as described by the emergency diesel generator major overhaul work package. The component which caused the failure was not designated for maintenance and was not removed as interference. Therefore, it is reasonable to conclude that the cause for failure was "independent of the maintenance performed," even though it was identified through post maintenance testing, and thus the failure is not eligible for exclusion per the existing guidance.

Mitigating Systems
MS06 MS07 MS08 MS09 MS10

ID 459

Posting Date 07/16/2008

Question Time of discovery is used in the Mitigating Systems Performance Index (MSPI) for the assignment of train unavailable hours when the train cannot perform one or more of its MSPI monitored functions. The time of discovery is the start time for the train unavailable hours and the end time is when the trains capability to perform its monitored function(s) is restored. Typically, time of discovery occurs when a component failure happens causing the train to become unavailable. At other times, a component degraded condition may occur that prevents a train from performing its monitored function(s). In some of these cases it may take an evaluation to determine the impact of the degraded condition on the trains monitored function(s).

An assumption of MSPI is that monitored function(s) are promptly restored after a component failure. (Promptly is not defined.) Therefore, degraded conditions are expected to be evaluated promptly so that if a degraded condition prevents the performance of a monitored function, the monitored function can be restored quickly.

For MSPI purposes, the time of discovery is when a component failure occurs that renders a train unable to perform a monitored function. For a component degraded condition, time of discovery is when an evaluation is completed that determines that a train is/was unable to perform a monitored function. In both of these cases, train unavailability is assigned only for the time it takes to restore the ability to perform the monitored function(s) from the time the failure is known. In the case of a component degraded condition that renders a train unable to perform a monitored function, an appropriate type failure is assigned to the component in MSPI unreliability to account for the amount of time that the condition existed prior to discovery, when the component was in an unknown failed state.

Delays in initiating or completing evaluations of degraded conditions would be addressed through the inspection process.

Response Change the guidance as follows:

Page 29, section titled Indicator Definition, second paragraph, line 20. Add the following sentence after the last sentence (in the parentheses) of the second paragraph; Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s). In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process.

Page F-5, section titled Actual Train Unavailability, paragraph starting Unplanned unavailable hours: After the first sentence of this paragraph add Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s). In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process.

Page F-5, section titled Actual Train Unavailability, paragraph starting Unplanned unavailable hours: In the third sentence on line 39, revise the sentence to read oil leak that was determined to have resulted in the equipment being non-functional

The background information above should be placed in a performance indicator basis document such as IMC 0308.

ID 435

Posting Date 12/05/2007

Question In summary, the licensee stated that *... unavailability should accrue on August 18, 2004 when the failure occurred.* The licensee believes that the duration between July 21 and August 19, should be counted as Fault Exposure Hours. However, Region IV staff does not agree with this position. The licensee had ample opportunity to identify and correct this condition, as was stated in a previously cited 10 CFR 50, Appendix B, Criterion XVI violation. Region IV staff believes the duration that DG-1 was non-functional should be counted as Unavailability Hours.

Response The 29-day period beginning on July 21, 2004 covering when the emergency diesel generator (EDG-2) was not capable of performing its risk-significant function, and with the licensee assuming it was functional, should not be counted as unplanned unavailability.

The situation and facts in this FAQ are similar to the circumstances in the Kewanuee EDG FAQ (FAQ 69.2) in that the question of what is meant by the term discovery (of an equipment failure) is in question. Although the Kewaunee FAQ was resolved by an appeal decision and was a site-specific response, the area of the guidance impacting both licensees is the same.

After careful weighing of the facts in this situation, along with the Kewaunee appeal decision (FAQ 69.2), the staff believes that based on the current wording of NEI 99-02 (Revisions 4 & 5), that periods of time when the EDG is not capable of performing is risk-significant function, and where the licensee has not recognized this unavailability, unplanned UA should not be counted.

The part of the NEI 99-02 Appendix F guidance that prompted this FAQ is focused on what is meant by the term discovery, as stated on page F-22 of NEI 99-02, Revision 4. Both the staff and the industry recognize that this aspect of the guidance is not clear and thereby there is no current consensus on how to interpret this definition. Further, this response is also not meant to provide a replacement for that definition.

ID 434

Posting Date 12/05/2007

Question On September 6, 2007, LaSalle County Station identified an error in the then-current PRA model, designated as 2006B. LaSalle had implemented the 2006B model prior to the end of the second quarter 2007. In accordance with the guidance, the 2006B model was therefore effective for the third quarter 2007 MSPI data submittal, and was due to be incorporated into the MSPI Basis Document and CDE by September 30, 2007. Additionally, this PRA modeling error existed in the 2006A PRA model, which was effective first quarter 2007 and used for the second quarter MSPI data submittal. Because of the error in the 2006A model, the MSPI PRA values for the second quarter 2007 were in error. It should be noted that the error resulted in approximately an order of magnitude change in Birnbaum values for the Residual Heat Removal System in the non-conservative direction, and thus resulted in under-reported MSPI values. The error did not affect any MSPI thresholds for either the second quarter or third quarter data.

The prior model, 2003A, was used for initial MSPI development and was in place for MSPI purposes through the end of the first quarter of 2007. No significant errors in the 2003A PRA model affecting MSPI values are known to exist.

Given that the error in the 2006A and 2006B model was non-conservative and was discovered prior to the end of the third quarter 2007, LaSalle decided to rescind the 2006A and 2006B models prior to the end of the third quarter and re-instate the 2003A model as the model of record until corrections could be made.

For the third quarter MSPI data submittal, LaSalle chose to use the 2003A model to develop MSPI data. This was done after consideration of the non-conservative nature of the error, the desire to not knowingly provide inaccurate data to the NRC, and after discussion with the site Senior Resident Inspector. A comment was placed in the data submittal identifying that an FAQ would be generated to resolve the deviation from the NEI guidance.

Despite the guidance that states that the model of record at the beginning of the quarter should be used for MSPI data reporting, LaSalle requests that this FAQ allow use of the 2003A model for MSPI data for the third quarter 2007.

Response LaSalle should use the 2006B model for MSPI data for the third quarter 2007 data in accordance with the NEI 99-02 Revision 5 guidance. The 2006B model was the model of record at the beginning of the third quarter and is thus required to be used for MSPI calculations. LaSalle should not correct second quarter data.

ID 432

Posting Date 10/18/2007

Question This FAQ proposes a guidance change to improve consistency of the guidance and allow flexibility in the timing of CDE entries made to reflect changes in site MSPI basis documents.

The current MSPI guidance (NEI 99-02, Rev 5) states the following regarding changes to baseline information:

Page 30, lines 35-40 and Page 31, lines 1-12 (regarding changes to PRA parameters):
The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter. Changes to the CDE database and MSPI basis document that are necessary to reflect changes to the plant specific PRA of record should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the MSPI coefficients. Any PRA model changes will take effect the following quarter (model changes include error, corrections, updates, etc.)

For example, if a plants PRA model of record is approved on September 29 (3rd quarter), MSPI coefficients based on that model of record should be used for the 4th quarter. The calculation of the new coefficients should be completed (including a revision of the MSPI basis document if required by the plant specific processes) and input to CDE prior to reporting the 4th quarters data (i.e., completed by January 21).

Page F-8, line 44 and following to Page F-9, line 3 (regarding changes to baseline planned unavailability):
The baseline planned unavailability should be revised as necessary during the quarter prior to the planned maintenance evolution and then removed after twelve quarters. A comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability is changed at the discretion of the licensee. Revised values will be used in the calculation the quarter following their update.

Page F-23, lines 38-40 (regarding changes in estimates of demands):
The new estimates will be used in the calculation the quarter following the input of the updated estimates into CDE.

Event or circumstances requiring guidance interpretation:

The concern is that the guidance is unnecessarily restrictive regarding CDE entry for changes in baseline planned unavailability and estimated demands, especially when compared to the guidance for PRA model changes. If a plant makes a change to its basis document for baseline planned unavailability or estimated demands, these values should not be used until the quarter following the change. However, sites should be allowed the flexibility to enter these changes into CDE during the data submittal period at the beginning of the new quarter following basis document revision. This allows the site time to make the entry into CDE. The site basis document can be easily audited to ensure that the change was approved prior to the beginning of the new quarter.

Response Plain Specific PRA **(Page 30, line 35 Page 31, line 12)**

The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant.

Specific requirements appropriate for this PRA application are defined in Appendix G. Any questions related to the interpretation of these requirements, the use of alternate methods to meet the requirements or the conformance of a plant specific PRA to these requirements will be arbitrated by an Industry/NRC expert panel. If the panel determines that a plant specific PRA does not meet the requirements of Appendix G such that the MSPI would be adversely affected, an appropriate remedy will be determined by the licensee and approved by the panel. The decisions of this panel will be binding.

Clarifying Notes **(Page 32, lines 4-8)**

Documentation and Changes

Each licensee will have the system boundaries, monitored components, and monitored functions and success criteria which differ from design basis readily available for NRC inspection on site. Design basis criteria do not need to be separately documented. Additionally, plant-specific information used in Appendix F should also be readily available for inspection. An acceptable format, listing the minimum required information, is provided in Appendix G.

Changes to the site PRA of record, the site basis document, and the CDE database should be made in accordance with the following.

Changes to PRA coefficients. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter. Changes to the CDE database and MSPI basis document that are necessary to reflect changes to the plant specific PRA of record should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the MSPI coefficients. Any PRA model changes will take effect the following quarter (model changes include error, corrections, updates, etc.). For example, if a plants PRA model of record is approved on September 29 (3rd quarter), MSPI coefficients based on that model of record should be used for the 4th quarter. The calculation of the new coefficients should be completed (including a revision of the MSPI basis document if required by the plant specific processes) and input to CDE prior to reporting the 4th quarters data (i.e., completed by January 21).

Changes to non-PRA information. Updates to information that is not directly obtained from the PRA (e.g., unavailability baseline data, estimated demands/run hours) will become effective in the quarter following an approved revision to the site MSPI basis document. Changes to the CDE database that are necessary to reflect changes to the site basis document should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the basis document.

SECTION F 1.2.2 (PAGE F-8, LINE 44 THROUGH PAGE F-9, LINE 3)

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.

Some significant maintenance evolutions, such as EDG overhauls, are performed at an interval greater than the three year monitoring period (5 or 10 year intervals). The baseline planned unavailability should be revised as necessary in the basis document during the quarter prior to the planned maintenance evolution and then removed after twelve quarters. A comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability is changed at the discretion of the licensee. Revised values will be used in the calculation the quarter following the basis document revision.

ID 431

Posting Date 10/18/2007

Question Clarification of the guidance related to whether time of discovery is when the licensee first becomes aware that the component cannot perform its monitored function or is when the licensee completes a cause determination and concludes the component would not have performed its monitored function at some earlier time, similar to the situation described in the event section below.

Lines 19-20 on page F-5 of section F 1.2.1 in discussion about train unavailable hours. Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the trains monitored functions.

Lines 18-19 on page F-22 of section F 2.2.2. Unplanned unavailability would accrue in all instances from the time of discovery or annunciation consistent with the definition in section F 1.2.1.

Lines 34-40 on page F-5 of section F 1.2.1. *Unplanned unavailable hours:* These hours include elapsed time between the discovery and the restoration to service of an equipment failure or human error (such as a misalignment) that makes the train unavailable. Unavailable hours to correct discovered conditions that render a monitored component incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that resulted in the equipment being non-functional even though no demand or failure actually occurred.

Event or circumstances requiring guidance interpretation:

On June 28, 2006 a small leak (one drop per minute) was identified in a diesel generator fuel oil system. A work request was written on that day to repair the leak, but no operability determination or repair was performed. On July 20, the diesel was successfully run for 2.6 hours with the leak still present. On August 17, the diesel was run for 0.35 hours, at which time it was identified that the leak became more significant. The diesel was shut down 1 hour after being started. At this time the diesel was declared inoperable. The diesel was considered operable up until the time the leak became more significant on August 17. The fuel line was repaired and the diesel was returned to service August 18.
A diesel failure was assigned in the MSPI data for 3Q06 and unplanned unavailability hours were assigned for the August 17-18, 2006, time needed to restore the diesel to service.

Response Kewaunee Power Station believes that in MSPI, unavailable hours are counted only for the time required to recover the trains monitored functions, and, therefore, the time of discovery for the purposes of assigning unplanned unavailable hours starts from the time the diesel was declared inoperable on August 17, 2006, and that the guidance adequately states this. Unavailability, prior to the determination that the failure affected the ability of the diesel to perform its monitored function, is actually fault exposure, which is not included in the MSPI unavailability calculation. Since performance deficiencies were noted for this event, the Significance Determination Process (SDP) was used to characterize the risk of the event and this process evaluated the fault exposure period to determine that risk.

The example given on Page F-5, lines 38-40 *(An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that resulted in the equipment being non-functional even though no demand or failure actually occurred)* would imply that the discovery of the oil leak in June should be the starting point for unavailability. However, the determination that the degraded condition affected the ability of the diesel to perform its monitored function was not made until some time after the failure

APPEAL DECISION

After weighing the arguments presented by staff and industry in this FAQ, I've concluded that the MSPI "unavailability" time does not include periods of "failed discovery," such as that which occurred at Kewaunee from June 28, 2006 through August 17, 2006. I find this to be the interpretation most consistent with the definition of "unavailability" contained on page 29 of NEI 99-02, Revision 5, and on balance, the most appropriate way to read the guidance of NEI 99-02 in its entirety.

I recognize that the MSPI unreliability index value may under-represent conditional core damage frequency for situations in which failed discovery extends longer than a routine surveillance period. While this is less exact for the purpose of measuring system performance, it is consistent with the recognized limitation that MSPI does not capture the effect of latent defects such as design errors that are identified through analysis rather than by surveillance testing. This limitation in the MSPI is one of the factors leading to the use of both the MSPI Performance Indicator and the inspection and assessment process when evaluating regulatory response under the ROP. The ROP significance determination process is an appropriate tool for addressing the performance issues associated with failed discovery, such as occurred at Kewaunee.

FAQ effective for 3Q07 data submittal

Mitigating Systems
MS07 MSPI High Pressure Injection Systems

ID 430

Posting Date 09/19/2007

Question NEI 99-02 Guidance needing interpretation (include page and line citation):

Page F-48, Section F.5, lines 45-46, and page F-49, Section F.5, lines 1-7 of the NEI 99-02, Appendix F guidance describes train determination for three-loop Westinghouse plants; however, the system described therein does not represent the HHSI system at Turkey Point. Therefore, there is no system-specific guidance for HHSI which is applicable to the HHSI system at Turkey Point.

Event or circumstances requiring guidance interpretation:

During the week of June 4-8, 2007, an audit of the PTN MSPI programs was conducted. During his review of the PTN MSPI Basis Document proposed update, the technical expert brought in for the audit noted the uniqueness of Turkey Points HHSI system in that both the Unit 3 and Unit 4 HHSI pumps start on an SI signal from either unit, and all of them feed the stricken unit. He also noted that the generic CCF factors for Turkey Point (NEI 99-02, Table 3) imply that there are 4 pumps being monitored for each unit. The NEI 99-02 guidance for Westinghouse 3-loop plants (pages F-48 and 49), which states that 3-loop plants have 3 pumps, one of which is an installed spare, does not apply for the Turkey Point 3-loop configuration.

For reliability monitoring, the two Unit 3 HHSI pumps are monitored for Unit 3, and the two Unit 4 HHSI pumps are monitored for Unit 4. For unavailability monitoring, the two Unit 3 HHSI pump trains and the two Unit 3 discharge valves are monitored for Unit 3, and similarly, the two Unit 4 HHSI pump trains and two Unit 4 discharge valves are monitored for Unit 4. The opposite-unit pump trains are not monitored for unavailability for either unit. The technical expert for the audit recommended that the opposite-unit HHSI pumps be added for unavailability and reliability monitoring.

Response FPL proposes to add the opposite-unit HHSI pump trains for unavailability monitoring for each unit, and the opposite-unit HHSI pumps for reliability monitoring for each unit. This is consistent with the HHSI system as it is modeled in the Turkey Point PSA. Although the opposite-unit HHSI pumps are cooled by the opposite-unit component cooling water (CCW) pumps, it is proposed that they not be added as they are already monitored for their associated unit, and their Birnbaum importances for the opposite-unit are several orders of magnitude less than their Birnbaum importances for their own unit.

Due to the current CDE software limitation of not being able to accommodate a mid-stream change in the number of monitored unavailability trains, the addition of the opposite-unit HHSI trains for unavailability monitoring will be accomplished by adding the trains retroactive to MSPIs inception. The PRA parameters in these updates will be consistent with the PRA model in effect at the time.

Revise NEI 99-02, Appendix D to include the Turkey Point HHSI configuration. The current guidance for three-loop Westinghouse plants in Appendix F does not apply to Turkey Point.

If appropriate, provide proposed rewording of guidance for inclusion in next revision:

<u>Issue:</u> The Turkey Point High Head Safety Injection (HHSI) design is different than the description provided in Appendix F for Train Determination. Therefore, there is no system-specific guidance for HHSI which is applicable to the HHSI system at Turkey Point.
At Turkey Point, each unit (Unit 3 and Unit 4) has two HHSI pumps. The Unit 3 and Unit 4 HHSI pumps start on an SI signal from either unit, and all of them feed the stricken unit. Should the Turkey Point reporting model be

revised to address the four train approach?

Resolution: Yes. In order to ensure accurate reporting, add the opposite-unit HHSI pump trains for unavailability monitoring for each unit, and the opposite-unit HHSI pumps for reliability monitoring for each unit. Although the opposite-unit HHSI pumps are cooled by the opposite-unit component cooling water (CCW) pumps, they should not be added as they are already monitored for their associated unit, and their Birnbaum importances for the opposite-unit are several orders of magnitude less than their Birnbaum importances for their own unit.

Emergency Preparedness
EP01 Drill/Exercise Performace

ID 453

Posting Date 05/14/2008

Question If a licensee were to wait until the ERO assignment process was completed before crediting the DEP performance indicator for an ERO-member-in-training, then the opportunity could be counted in a reporting period other than the one in which the performance enhancing experience occurred. At North Anna, a performance enhancing experience was provided to new ERO member before they assumed their ERO position. The ERO member assumed their ERO position one day later; however, that day spanned reporting periods.

Question: How and when should DEP PI opportunities for ERO-members-in-training be counted?

Response

PI opportunities and participation credit should not be counted for ERO-members-in-training. DEP opportunities are only counted for plant staff members who are currently assigned to fill a key position on the ERO.

The participation PI tracks Key ERO members assigned to the ERO. The key word here is assigned. Trainees are not assigned to the ERO and therefore DEP opportunities or participation does not count.

Data reporting may be affected in accordance with this FAQ at some plants. There is no need to modify past record keeping practices based on this FAQ. Record keeping practices should only be modified.

Discussion

If a Key ERO member trainee participates in a performance enhancing experience as part of the qualification process, then the licensee may count the trainees performance, (success or failure) in the Drill/Exercise PI (EP01) for the quarter in which the opportunity occurred. All trainee EP01 performance enhancing experiences must be determined in advance in accordance with NEI 99-02 clarifying notes.

If the trainee performance is counted as a success, then they may be assigned to the ERO. If the trainee performance is a failure, then they may undergo remediation prior to assignment to the ERO. If a performance enhancing experience is required for remediation, it may or may not be included in the EP01 PI, as described above. In either case, when the trainee is actually assigned to the ERO, then all their EP 01 performance enhancing opportunities, whether a success or failure are included in the EP01 metric in that quarter. For EP02, the trainees most recent participation in a performance enhancing experience that was included in the EP01 PI, whether during qualification or remediation, would apply.

Response NEI 99-02 Revision 5, page 43, Line 31 defines EP01 as The percentage of all drill, exercise, and actual opportunities that were performed timely and accurately by Key Positions, as defined in the ERO Drill Participation indicator, during the previous eight quarters.

NEI 99-02 Revision 5, page 51, Line 3 identifies the purpose of EP02, This indicator tracks the participation of ERO members assigned to fill Key Positions in performance enhancing experiences and through linkage to the DEP indicator ensures that the risk significant aspects of classification, notification, and PAR development are evaluated and included in the PI process. This indicator measures the percentage of ERO members assigned to fill Key Positions who have participated recently in performance-enhancing experiences such as drills, exercises, or in an actual event.

NEI 99-02 Revision 5, page 51, Line 11 defines EP02 as The percentage of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event during the previous eight quarters, as measured on the last calendar day of the quarter.

NEI 99-02 Revision 5, page 51, Line 18 identifies the data reporting elements as

total number of ERO members assigned to fill Key Positions

total number of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event in the previous eight quarters

NEI 99-02 Revision 5, page 52, Line 24 provides Clarifying Notes, When the performance of **ERO members assigned to fill** Key Positions includes classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) for participation of those Key Positions to contribute to ERO Drill Participation. **When a performance enhancing experience occurs prior to an ERO member being assigned to a Key Position in the ERO (qualifying drill), then the classification, notification, or PAR development success rate shall contribute to the Drill/Exercise (DEP) at the time the member is assigned to the ERO. Drill Participation credit will be the ERO members most recent participation in a performance enhancing experience that was included in the EP01 PI.**

Application of this resolution and revision to NEI 99-02 would ensure that the performance, positive or negative, of all ERO members assigned to fill Key Positions is actually reflected in the EP01 PI. It would provide a fuller indication of the state of proficiency of the ERO members assigned to fill Key Positions. It would also prevent deferral of performance enhancing experiences from incumbent ERO members assigned to fill Key Positions to newly-qualified ERO members assigned to fill Key Positions.

NEI 99-02 Revision 5, page 53, insert at Line 48 Drills performed by an individual before being assigned to a Key Position in the ERO may be counted once the individual is assigned to the ERO as long as the performance enhancing experience(s) contributes to the Drill/Exercise (DEP) metric.

NEI 99-02 Revision 5, page 45 insert at Line 39 When a performance enhancing experience occurs before an individual is assigned to a Key Position in the ERO, then opportunities for that individual that were identified in advance shall contribute to the Drill/Exercise (DEP) metric at the time the member is assigned to the ERO.

Emergency Preparedness
EP03 Alert and Notification System

ID 438

Posting Date 12/05/2007

Question On May 5, 2007, at 1300 hours, during the routine siren testing of the CNP alert and notification system (ANS), the initial attempt to actuate the sirens did not achieve the anticipated results (none of the 69 sirens being tested received an actuation signal). Siren testing is performed by Berrien County personnel located in the local 911 dispatch center (Primary Activation Center). An electronic map board is located within the facility and provides indication when a siren is actuated. The dispatcher did not get the expected response after the first attempt, i.e., the map board did not show any sirens were actuated. During the test, the dispatcher was in telephone communication with the telecommunications technician responsible for siren testing and maintenance since this was the dispatchers first testing opportunity after completion of training. As provided for by siren testing procedure, the dispatcher informed the telecommunications technician that she did not get the expected response upon the first activation. Also in accordance with the established siren testing procedure, the telecommunications technician directed the dispatcher to re-perform the test sequence. A total of five attempts were made over an eight minute period (specifically, the initial attempt at 1300 hours plus four additional attempts). Note that a simultaneous transmission on a media frequency which occurs concurrently with the siren actuation transmission did occur with each actuation attempt as expected. The telecommunications technician drove to the Backup Activation Center to verify indication on the map board at that location. When he confirmed that indication at the Backup Activation Center was identical to the 911 dispatch center, the telecommunications technician directed the dispatcher to initiate another siren activation attempt. The sirens responded as expected on this attempt (six) at approximately 1323 hours.

Note that the CNP siren system consists of 70 sirens total. On May 5, 2007, only 69 sirens were tested. The county had tested the other siren on May 4, 2007, due to community activities (parade).

No maintenance was performed between the initial scheduled attempt and the successful attempt. The apparent cause of this event was determined to be an intermittent dead spot on a potentiometer associated with the siren activation circuitry. No indications of equipment failure or malfunction could be identified on May 5, 2007, after the successful siren test. However, on May 26, 2007, a lightning strike at the primary activation center caused the failure of the 155.925 MHz receiver, causing the encoding equipment to operate abnormally. During the post-maintenance testing after replacement of the affected equipment, the telecommunications technicians saw indications that duplicated the siren response on May 5. Since they were present in the affected facility, they were able to trace the problem to a potentiometer on the microphone input board. The potentiometer was wiped and the problem could not be repeated. The telecommunications technicians noted that an intermittent failure on this type of device is not unusual. A new potentiometer was installed.

<u>Conclusion Siren Testing was Successful</u>

The ANS Reliability PI reports the percentage of ANS sirens that are capable of performing their function as measured by periodic siren testing in the previous 12 months. The only performance criterion is successful completion of a siren test. The guidance does not specify how a test is to be performed, i.e., the specific steps of a test are not prescribed. FEMA reviews the siren testing procedures. As long as the dispatcher follows the guidance to perform the siren test and the test is not exited for maintenance or other corrective actions, then activation of the sirens within the bounds of the guidance using multiple signals is a success. This interpretation is supported by the response in Archived FAQ 232.

The NRC has indicted that they believe the May 5, 2007, siren test was a failure solely based on the amount of time required to activate the siren during the test sequence. CNPs position is that time is not a factor in the performance indicator. CNPs position is supported by FEMAs statements in the Federal Register, Volume 67, Number 80, dated April 25, 2002. FEMA has recognized that initiation of the ANS needs to be done in a timely manner following notification to the offsite response organization by the nuclear power plant. Their position is that decision makers are tasked with the responsibility to use judgment based on the conditions or scenario. Therefore, they have not established a firm time for ANS activation after notification.

The NRCs position is based on a 10 CFR 50 Appendix E, design objective of **about** (emphasis added) 15 minutes for siren activation. This design objective has never been part of the PI guidance for a successful siren test. The PI guidance definition of a successful siren test does not include a time-related performance criterion. The NRC is attempting to add a new criterion to the definition of successful siren tests by imposing the Part 50,

Appendix E design objective. The design objective may be subject to inspection but is not a factor in PI reporting.

Accepting NRCs position that the May 5, 2007, siren test was a failure would inappropriately lead to a Yellow PI for CNP. The Yellow performance band shows a decline in licensee performance that is still acceptable with cornerstone objectives met, but represents a significant reduction in safety margin. CNPs siren performance has not experienced a significant reduction in safety margin. In fact, the CNP ANS is healthy as evidenced by routine polling data and sustained previous performance. The delay in activation of this one test should not be allowed to skew CNPs performance. The method of calculation varies among licensees; some licensees include polling in their testing procedure; others include growl tests; still others only activate sirens the minimum of one time per year. When the denominator is small (based on approved testing), small changes in the numerator can drive performance from the Green band to the unacceptable Yellow performance band. Such significant changes in Performance Indicators should be based on actual performance and not disparate calculation methods. CNP uses monthly testing of 70 sirens for the PI calculation. While CNP still believes the test was successful, if the siren test is considered a failure, CNP moves from Green to Yellow (Column 3). CNP station performance is not Column 3, and a 95002 inspection is not warranted based on this one incident.

Question: Multiple activation signals were sent to all sirens being tested. The sirens did not initially appear to respond. Additional attempts to actuate the sirens were made in accordance with existing guidance. On the sixth attempt, all sirens being tested successfully activated. Can this be considered a successful test of the siren system?

Response No, this is not a successful test of the siren system. During the performance of the test, the dispatcher sought the aid of a siren telecommunications assistant during the performance of the test and received his direction to make multiple attempts to activate the sirens. The procedure did not direct the use of multiple activation signals, rather the technicians input prompted the dispatchers additional attempts from the same control station sending the same activation signal. Further, the ANS PI determines the reliability of the sirens to function when tested (silent, growl, siren sound test). Prompt notification of the public within about 15 minutes is required per Appendix E to 10 CFR Part 50. To meet this regulatory requirement, it should be demonstrated that the sirens have the capability to function reliably.

It is recognized that if the siren system cannot be activated at its initial test location, the system can be activated from a redundant location. However, no attempt was made to activate the sirens from a redundant location. Sirens did not activate until 23 minutes after the procedure was initiated. Clearly, for this specific situation, the sirens did not function reliably.

Physical Protection
PP02 PP03

ID 443

Posting Date 03/19/2008

Question On February 28, 2008, NRC issued RIS 2008-04 to inform licensees that the Personnel Screening Program and the Fitness-for-Duty/Personnel Reliability performance indicators used in the Security section of NEI 99-02 will be discontinued. These PIs were discontinued because the aspects of security programs measured by the PIs are assessed by the security baseline inspection program and that this redundancy challenged efficiency and caused undue regulatory burden. In addition, the data gained and insights provided by these PIs have been of limited additional value to the security ROP and are already reported to the NRC through 10CFR reporting requirements.

Response Delete all references to PP02 and PP03 in NEI 99-02.