

## SwLONHR PI PURPOSE

Source:

Letter from Bruce A. Boger to Stephen D. Floyd dated March 16, 2004

Statement of SwLONHR Purpose:

The staff believes that a PI that identifies plant transients beyond routine scrams that have risk-significance in some important accident sequences has merit, and is presently worth retaining. The scrams with loss of normal heat removal PI provides a performance insight that is not obtainable from the unplanned scrams PI or the significance determination process.

SECY-99-007, Attachment 2, Appendix A, page A-4

(A) separate count is made of risk-important scrams over a 12 quarter moving sum to differentiate these scrams from the scrams without any complications. Risk-significant scrams = Scrams with LOCA, SGTR, LOOP, Total Loss of Heat Sink, Total Loss of Feed-water, or Scrams with a failure (of) one or more trains of the SSPI systems.

From the above, we can state the purpose of the Scrams with Loss of Normal Heat Removal PI as follows:

To identify plant transients beyond routine scrams that are complicated by additional problems that have risk-significance in some important accident sequences.

**DRAFT  
NEI 99-02, APPENDIX E**

**“FREQUENTLY ASK QUESTION (FAQ) PROCESS”**

**I. INTRODUCTION:**

Since the inception of the Reactor Oversight Process (ROP), over 350 FAQs have been evaluated and dispositioned by the ROP Task Force Committee.

As the ROP process has gained maturity, the need has been recognized for additional guidance and formality on the preparation, review, and approval process for FAQs, and to improve the overall process efficiency.

The initial goals of the FAQ process are provided in Section 1 of NEI 99-02 {Note: when incorporated into NEI 99-02 the following will be deleted – it is for the review cycle only}:

*“The mechanism for resolving interpretation issues with NEI 99-02 is the Frequently Asked Questions (FAQ) process. FAQs and responses regarding interpretations of this guideline will be posted on the NRC Website ([www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.html](http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.html)). FAQs posted on the NRC Website represent NRC approved interpretations of performance indicator guidance and should be treated as an extension of NEI 99-02.*

*“FAQs should be submitted as soon as possible once the Licensee and resident inspector or region has identified an issue on which there is not agreement. If the Licensee is not sure how to interpret a situation and the quarterly report is due, an FAQ should be submitted and a comment in the PI comment field would be appropriate. It is incumbent on NRC and the Licensee to work expeditiously and cooperatively, sharing concerns, questions and data in order that the issue can be resolved quickly.*

*“The NRC Website will identify the date of original posting for FAQs and responses. Unless otherwise directed in an FAQ response, FAQs are to be applied to the data submittal for the quarter in which the FAQ was posted and beyond. For example, an FAQ with a posting date of 3/31/2000 would apply to 1st quarter 2000 PI data, submitted in April 2000 and subsequent data submittals. However, an FAQ with a posting date of 4/1/2000 would apply on a forward fit basis to 2nd quarter 2000 PI data submitted in July 2000. Licensees are encouraged to check the NRC Web site frequently, particularly at the end of the reporting period, for FAQs that may have applicability for their sites.*

*“Questions on this guideline may be submitted by email to [pihelp@nei.org](mailto:pihelp@nei.org). The email should include “FAQ” as part of the subject line. The emails should also provide the question and a proposed answer as well as the name and phone number of a contact person. The proposed question and answer will be reviewed*

*by NEI staff and will be discussed with NRC staff at a public meeting. Once approved by NRC, the accepted response will be posted on the NRC Website and incorporated into the text of this guideline when the next revision is issued (no more frequently than once per quarter)."*

This FAQ process therefore provides a mechanism for resolving questions concerning the implementation of NEI 99-02, and can be useful for engagement between the NRC and Industry on issues associated with the Reactor Oversight Process (PIs, Significance Determination Processes, Action Matrix, etc.).

It is clear that this process cannot be used to change any regulatory requirements promulgated through rules or orders. Its intent is to resolve interpretation and implementation issues in the context of existing guidance and/or requirements.

This Appendix provides additional guidance that shall be followed hereafter for all draft FAQs submitted for review.

## **II. DEFINITIONS:**

**Performance Indicator Clarifications:** The primary purpose of the FAQ process is to provide a formal framework to effect clarification on the interpretation of the guidance, and to resolve conflicting and/or ambiguous/unclear instructions in NEI 99-02.

- Example 1: NEI 99-02R2, page 20, states in part for Unplanned SCRAMS per 7,000 Critical Hours (IE03) "*... If, however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count.*" What constitutes "suddenly degrades" and "rapid response"?
- Example 2: NEI 99-02R2, page 29, states in part for Safety System Unavailability (MS01-04) "*... If additional time is needed to repair equipment problems discovered during the planned overhaul that would prevent the fulfillment of a safety function, the additional hours would be non-overhaul hours and/or potential fault exposure hours, and would count toward the indicator.*" Does "repair equipment problems" include the additional time (beyond the planning work window but less than the Technical Specifications allowable AOT) to improve equipment performance identified during post-maintenance testing, even though the equipment passed the post-maintenance test?

FAQs should follow the format of Attachment 1.

**Plant Specific Guidance:** A secondary purpose of the FAQ process occurs whenever NEI 99-02 contains instructions to licensees to submit a FAQ for

special cases where licensees with unique plant designs, or configurations, were not anticipated in NEI 99-02. While submitted using the FAQ process, these instances needing Plant Specific Guidance are treated on a case-by-case basis, and are placed in Appendix D of 99-02 (and posted on NRC and NEI Websites as plant-specific FAQs).

- Example 3: NEI 99-02R2, page 19, states in part for Unplanned Power Changes per 7,000 Critical Hours (IE03) “*... Anticipated power changes greater than 20% in response to expected problems (such as Accumulation of marine debris and biological contaminants in certain season) which are proceduralized but can not be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. 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.*” At our plant, micro-organisms such as Veligers (a small mussel found in the Great Lakes) periodically multiply to sufficient quantities to clog the intake screens, causing a down power to prevent a plant trip. If we did not have significant equipment problems with the intake screens’ performance (i.e., the screen’s capability should have been able to handle our expected average Summer influx of Veligers), can we exempt the down powers?

**Reactor Oversight Guidance:** A secondary purpose of the FAQ process occurs whenever the Reactor Oversight Process program elements (Action Matrix, SDPs, etc.) are unclear or subject to interpretation.

**Security Frequently Asked Questions:** On May 27, 2004, the Industry, NEI, and NRC agreed to a separate process for Security-related FAQs (SFAQ). The purpose of the SFAQ process is to provide an organized forum for Licensees and the NRC to resolve questions concerning the implementation of security requirement in a collaborative and open context. Issues involving enforcement actions, changes to regulatory requirements promulgated through rules or orders, or other regulatory actions, are not within the scope of this process. Therefore, all security-related issues, with the exception of issues associated with the NEI 99-02 Physical Protection PP-01 performance indicator, are to be directed to the SFAQ process. The questions that are evaluated may be categorized into the following topical areas:

- Design Basis
- Force-on-Force
- Training
- Access Authorization
- Security Plans

- Cyber Security
- Other

**Changes:** It is not the purpose of the FAQ process to effect new definitions to NEI 99-02. Proposed changes to the requirements of NEI 99-02 should be forwarded separately to the ROP Task Force for further discussion and evaluation.

- Example 4: NEI 99-02R2, page 15, states in part for SCRAMS with loss of normal heat removal “... *Such events are more risk-significant than uncomplicated scrams.*” Since PRA analysis can determine the conditional core damage probability (CCDP) for each scram, why not allow the PI to exempt scrams that increased risk (the CCDP) by < 1.0 E-6. Therefore, any scram below this risk threshold should not count. [Note: this suggested FAQ would constitute a new definition of the PI, and as such is not eligible for the FAQ process.]

**Judgments:** It should be rare when the FAQ process is called upon to simply “rule” on what counts or does not count as a “PI hit”. The FAQ process should be focused on the need for clarification of NEI 99-02 guidance, which will allow the subsequent disposition of issues. On very rare occasions, a dispute may come to the ROP Committee for judgment.

**Supporting Documentation:** A well-written FAQ provides appropriate references/quotes from NEI 99-02, to focus the issue before the ROP Committee. The template for FAQs is provided in Attachment 1. Plant history and operating conditions may be relevant, and should be included as supporting documentation – however; it is imperative that any supporting documentation be complete and accurate in all material respects. Inaccurate information or the omission of material information on plant design, plant performance, operator response, historical trends and data, in the supporting documentation could constitute a violation of 10CFR50.9.

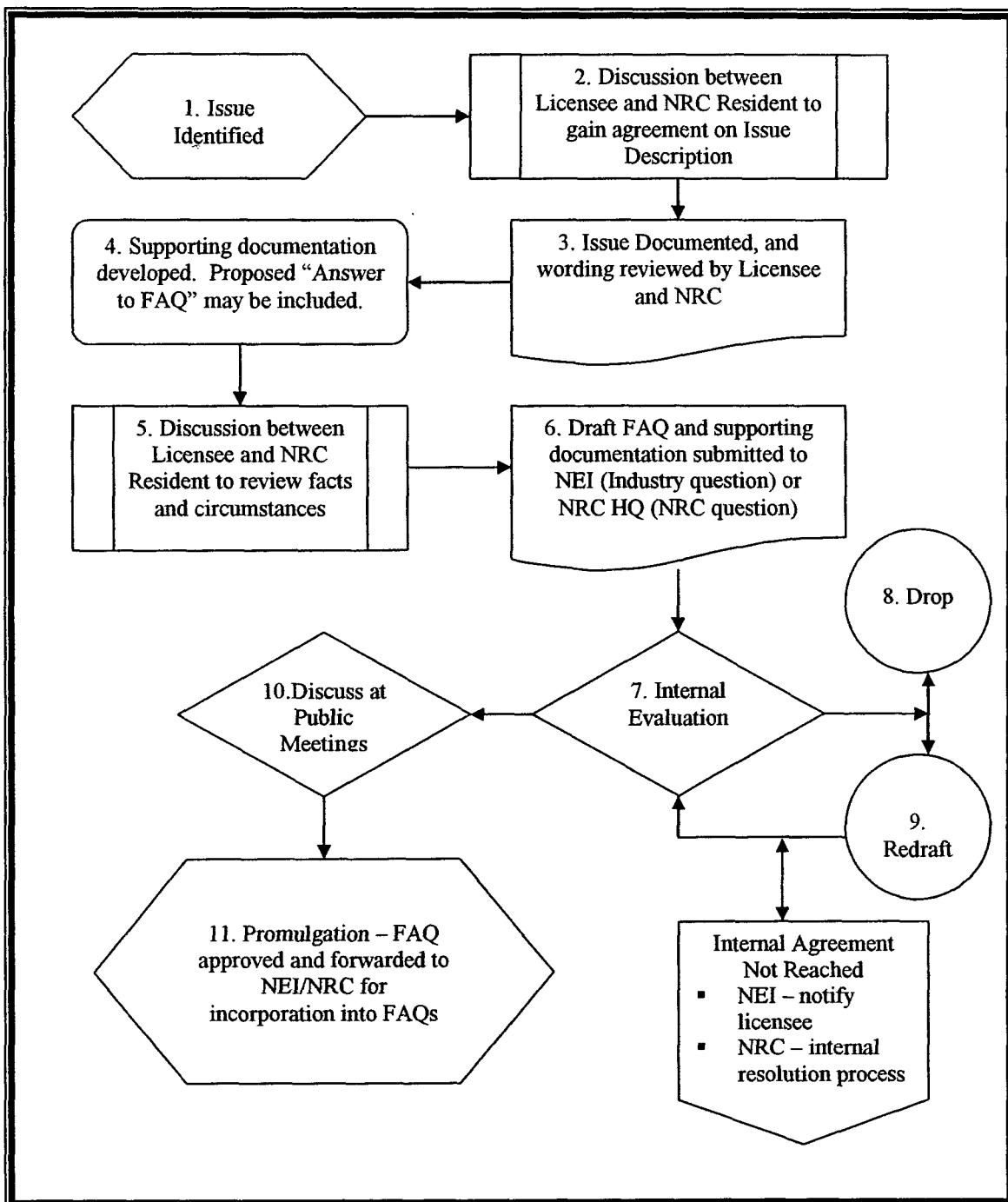
**External and Internal Agreement:** External and internal agreement is crucial to the FAQ process. Agreement is appropriate between the licensee and the resident inspector and/or Regional Office on the facts and circumstances surrounding the issue.

Agreement is desirable, but not required, on the exact phrasing of the FAQ. In cases when agreement cannot be reached on the exact phrasing of the FAQ, either party can submit separate FAQ wording.

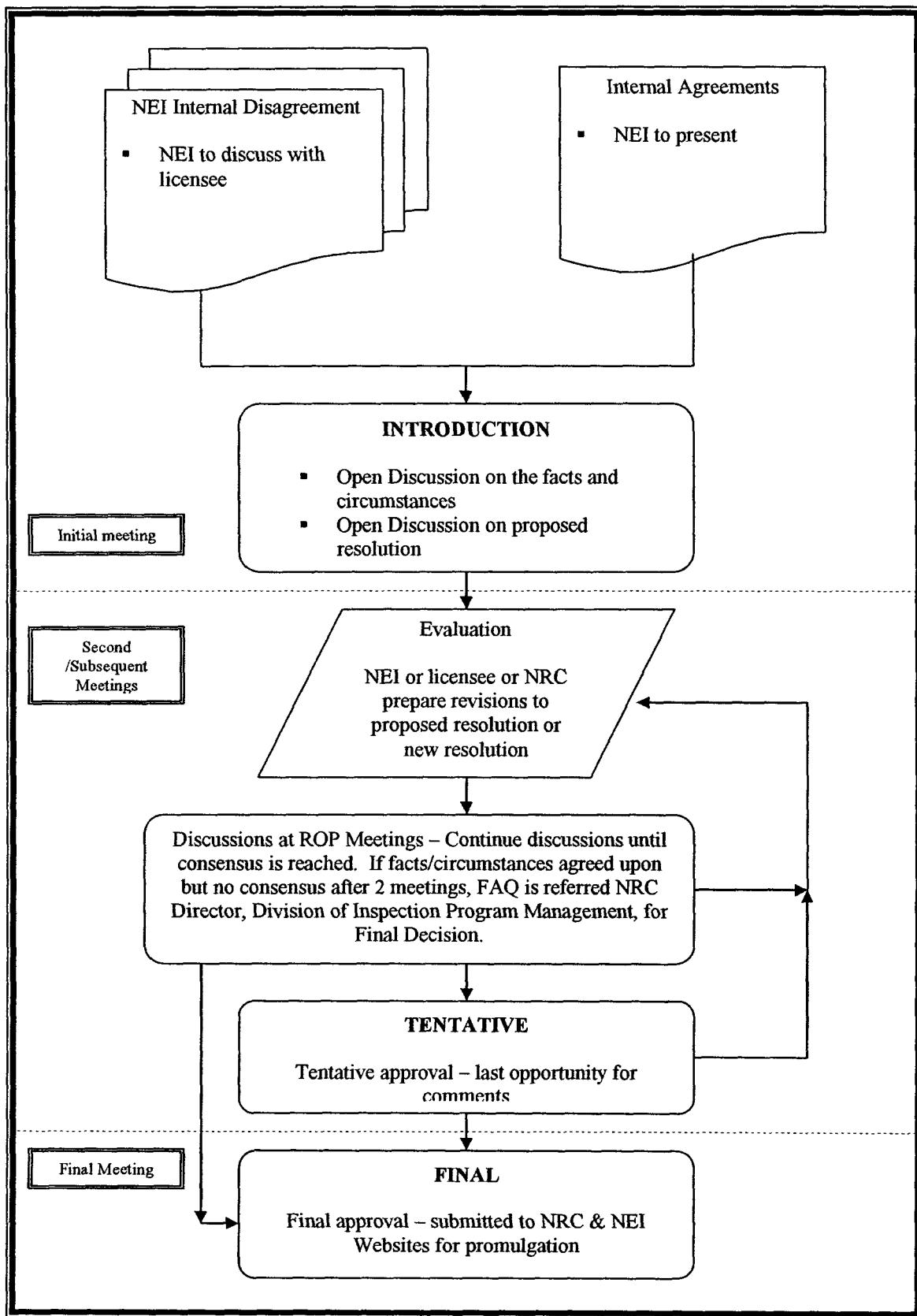
Internal agreement is desirable within the NRC, and within NEI/Industry. The NRC has internal programs and policies on resolving internal disagreements. When internal agreement cannot be reached between a licensee and NEI ROP Task Force, the NEI ROP Task Force Team Leader or a higher level within NEI will notify the licensee.

### **III. FAQ PROCESS FLOWCHART:**

The following is a graphical representation of the FAQ process:



Step 10 "Discuss at Public Meetings" is further described as:



**IV. NOTES ON PROCESS STEPS ABOVE:**

**Identification (Step 1)**

Either the NRC or Licensee may identify the need for a FAQ.

**External Agreement (Steps 2, 3, 4 and 5)**

External agreement is important to the FAQ process. External agreement is desirable on the facts and circumstances, documentation, and the wording of the FAQ between the licensee and the resident inspector and/or Regional Office. In cases when external agreement cannot be reached, either party can submit separate wording and/or documentation or feedback.

**Internal Agreement (Steps 6, 7, 8, and 9)**

Internal agreement is necessary between the resident inspector and/or Regional Office, and the NRC ROP Branch; and between the licensee and the NEI ROP Task Force. During this process, the FAQ may be revised, rewritten, or dropped.

When internal agreement cannot be reached between the licensee and NEI ROP Task Force, the NEI ROP Task Force Team Leader will notify the cognizant licensee representative.

When internal agreement cannot be reached between the NRC resident inspector and/or Regional Office and the NRC ROP Branch, the NRC has an internal mechanism for resolving such issues – internal NRC agreement processes are outside this procedure.

**Public Meeting Discussions (Step 10)**

A new FAQ is added to the agenda and brought to the NRC/NEI ROP Task Force for initial INTRODUCTION. Licensees and NRC resident inspectors and/or Regional Office personnel may be in attendance or participate by conference-bridge. However, if the FAQ is sufficiently written, and internal and external agreement on the facts and circumstances have been reached, the FAQ is expected to “stand on its own.”

The NEI ROP Task Force Team Leader or designee, or the licensee if it requests to do so, will present and lead the discussion on the facts and circumstances surrounding the FAQ. If NRC generates the FAQ, it will lead the discussion.

At the first meeting, the FAQ is discussed and potential resolution discussed. In most cases, the INTRODUCED FAQ is referred to the next meeting to allow internal stakeholder review and input into the proposed resolution wording.

If the proposed INTRODUCED FAQ’s resolution wording is not acceptable to NRC and/or NEI Task Force members, written alternative resolution shall be

prepared for discussion at the next meeting. INTRODUCED FAQs are then added to the NEI active FAQ LOG, written alternative resolutions are developed and provided to the NEI ROP Task Force Team Leader for inclusion in the FAQ LOG, and the active FAQ LOG is forwarded one week in advance of the NRC/NEI Task Force meeting to all NRC and NEI Task Force members.

At the second and any future meetings, both NRC and NEI Task Force members will discuss proposed resolution(s) until consensus is achieved. "Consensus" means the separate agreement between both the NRC and the NEI Task Force groups. Within each group, individuals may disagree and yet consensus can be achieved.

A FAQ can be withdrawn at any time; but for reconsideration, must re-enter this process at the beginning.

Once consensus is achieved between the NRC and NEI ROP Task Force members, the FAQ is marked "TENTATIVE" giving all parties approximately one month (next meeting) for a last appeal. TENTATIVE FAQs are then moved to "APPROVED" at the next ROP meeting if no objections/appeals are raised.

In some limited cases (involving an issue with no contention and where exigent resolution is needed), it is possible for the NRC/NEI Task Force to reach immediate consensus and the FAQ be moved directly to APPROVED. This is usually the exception.

Once the facts and circumstances are agreed upon, if consensus (See section VI) cannot be reached after two consecutive joint panel meeting, the FAQ is referred to the ~~NRC~~ Director, Office of Nuclear Reactor Regulation for a final decision.

DIPM

### Promulgation (Step 11)

Once a FAQ has been APPROVED, it is distributed to NEI ROP PI Contacts, and placed on the NRC and NEI websites. FAQs are effective upon issuance except when specifically noted within for an alternate effectiveness date.

## **V. CONSENSUS AND APPEAL PROCESS:**

NEI will manage the Industry FAQ process and work closely with each licensee and the NRC to provide an efficient and organized process for identifying, evaluating, and resolving questions. This process has been, and is expected to remain, collegial and seeks a consensus opinion whenever possible.

However, once the FAQ is introduced and all facts agreed upon, if the Joint NEI/NRC Reactor Oversight Panel cannot reach consensus after two consecutive panel meetings, the issue will be referred to the NRC Director, Division of Inspection Program Management (DIPM), for a final decision. The decision will be made following a public meeting where both sides will present their respective positions to the Director DIPM, and the Director DIPM can ask questions on the facts and circumstances.

Following the decision by the Director, DIPM, any additional appeal by the licensee to higher levels within the NRC are outside this process.

**VI. FAQ SUBMITTAL EXAMPLES:**

Attachment 2 contains illustrative examples of questions as a template for draft FAQs. The degree of detail and additional information is, of course, dependent upon the facts and circumstances.

{INSERT EXAMPLES – TO BE DEVELOPED W/NRC}

**ATTACHMENT 1**  
**DRAFT FAQ SUBMITTAL TEMPLATE**

Licensee/Plant: \_\_\_\_\_  
Date of Event: \_\_\_\_\_  
Submittal Date: \_\_\_\_\_  
Licensee Contact: \_\_\_\_\_ Tel/email: \_\_\_\_\_  
NRC Contact: \_\_\_\_\_ Tel/email: \_\_\_\_\_

Performance Indicator: \_\_\_\_\_  
Is this a request for a Site-Specific FAQ or a Generic FAQ? Site \_\_\_\_\_ Generic \_\_\_\_\_  
Effectivity: FAQ requested to become effective on \_\_\_\_\_

NEI 99-02 Guidance needing Interpretation (Attach additional sheets if required):  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Event description – facts and circumstances (Attach additional sheets if required):  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Do licensee and NRC resident/Region agree on the facts and circumstances? Yes \_\_\_\_\_  
No \_\_\_\_\_ (If no, attach additional sheets to describe disagreement)  
Potentially relevant existing FAQ numbers: \_\_\_\_\_

Proposed Resolution of NEI 99-02 Guidance, including mark-up revision to existing 99-02 wording (Attach additional sheets if required):  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
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\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

**ATTACHMENT 2**

**FAQ EXAMPLES**

TempNo.	PI	Question/Response	Status	Plant/ Co.
27.3	IE02	<p>Question: Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal Background Information: On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level. The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR."   The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required).   Verify the following:  TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum  No TDRFP trip signals are present  Depress TDRFP Turbine RESET pushbutton and observe the following  Turbine RESET light Illuminates  TDRFP High Pressure and Low Pressure Stop Valves OPEN  PUSH M/A increase pushbutton on the Manual/Automatic Controller station  Should this be considered a scram with the loss of normal heat removal?   Proposed Answer:  The ROP working group is currently working to prepare a response.</p>	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed	LaSalle
28.3	IE02	<p>Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated.   Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events.   As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump</p>	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

## FAQ LOG

## DRAFT

TempNo.	PI	Question/Response	Status	Plant/ Co.
		<p>(MFP) until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation.</p> <p>Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal.</p> <p>Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal?</p> <p><b>Response:</b> The ROP working group is currently working to prepare a response.</p>		
30.8	IE02	<p><b>Question:</b> Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal?</p> <p><b>Response:</b> The ROP working group is currently working to prepare a response.</p>	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
32.3a	IE02	<p><b>Question:</b> An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam</p>	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

TempNo.	PI	Question/Response	Status	Plant/ Co.
		<p>supply.</p> <p>When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip.</p> <p>It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue.</p> <p>The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs prior to recommencing the startup.</p> <p>Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?</p> <p><b>Response:</b></p> <p>Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves.</p> <p>During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.</p>		
34.6	IE02	Question:	3/20 Introduced	STP

TempNo.	PI	Question/Response	Status	Plant/ Co.
		<p>Should the following event be counted as a scram with loss of normal heat removal?</p> <p>STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the main turbine. Approximately 17 minutes after the Unit was manually tripped main condenser vacuum was broken at the discretion of the Shift Supervisor to assist in slowing the turbine. Plant conditions were stabilized using Auxiliary Feedwater and Steam Generator Power Operated Relief Valves. Main Feedwater remained available via the electric motor driven Startup Feedwater pump. Main steam headers remained available to provide cooling via the steam dump valves. At any time vacuum could have been reestablished without diagnoses or repair using established operating procedures until after completion of the scram response procedures.</p> <p>Scrams with a Loss of Normal Heat Removal performance indicator is defined as "<i>The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.</i>" This indicator states that a loss of normal heat removal has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of the main steam isolation valves or loss of turbine bypass capability. The determining factor for this indicator is whether or not the normal heat removal path is available, not whether the operators choose to use that path or some other path. The STP plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps are then designed to start on low steam generator levels. This is expected following normal operation above low power levels and in turn provides the normal heat removal.</p> <p>This design functioned as expected on December 15, 2002 when the reactor was manually tripped due to high turbine vibration. Normal plant operating procedures OPOPO3-ZG-0006 (Plant Shutdown from 100% to Hot Standby) and OPOPO3-ZG-0001 (Plant Heatup) state if Auxiliary Feedwater is being used to feed the steam generators than the preferred method of steaming is through the steam generator power operated relief valves. This can be found in steps 7.4 and 7.5 of OPOPO3-ZG-0001 and steps 6.6.5 and 6.6.10 of OPOPO3-ZG-0006. The note prior to 6.6.10 states "<i>the preferred method for controlling SG steaming rates while feeding with AFW is with the SG PORVs</i>".</p> <p>The normal heat removal path as defined in NEI 99-02 Revision 2 was in service and functioning properly for seventeen minutes after the manual reactor trip and would have continued to function had not the shift supervisor voluntarily broke condenser vacuum and closed the MSIV's. Interviews with the shift supervisor showed that the decision to break vacuum was two part. 1) Based on experience and reports from the field it was known that vacuum would need to be broken to support the maintenance state required for the main turbine and at a minimum to support timely inspection. 2) This would assist in slowing the turbine. The decision to break vacuum was not based solely on mitigating an off-normal condition or for the safety of personnel or equipment. Because Auxiliary Feedwater system had actuated and was in service as expected, the decision was made to use Auxiliary Feedwater and steam through the SG PORVs. As stated earlier, this is the preferred method of heat removal if the decision to use Auxiliary Feedwater is employed as supported by the normal operating procedures while the plant is in Mode 3. Main feedwater remained available via the electric motor driven Startup Feedwater pump and the main steam headers remained available to provide cooling via the steam dump valves if required. Discussion with the shift supervisor showed he was confident that at any time vacuum could have been readily recovered from the control room without the need for diagnoses or repair using established operating procedures if the need arose. An outside action would be required in drawing vacuum in that a Condenser Air Removal pump would require starting locally in the TGB. This is a simplistic, proceduralized and commonly performed evolution. Personnel are fully confident this would have been performed without incident if required.</p> <p>Closing the MSIVs and breaking vacuum as quickly as possible is not uncommon at STP. For a normal planned shutdown MSIVs are closed and vacuum broken within four to six hours typically to support required maintenance in the secondary. If maintenance in the secondary is known to be critical path than vacuum has been broken as early</p>	<p>3/20 Discussed 6/18 Discussed; Question to be revised to reflect discussion 7/24 Discussed</p>	

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		<p>as three hours and fifteen minutes following opening of the main generator breaker. The only reason that vacuum is not broken sooner is because in most cases it is needed to support chemistry testing.</p> <p>By limiting the flow path as described in NEI 99-02 for normal heat removal there is undue burden being placed on the utility. Only recognizing this one specific flow path reduces operational flexibility and penalizes utilities for imparting conservative decision making. Conditions are established immediately following a reactor trip (100% to Mode 3) that can be sustained indefinitely using Auxiliary Feedwater and steaming through the steam generator PORVs. This fact is again supported in the stations Plant Shutdown from 100% to Hot standby and Plant Heatup normal operating procedures. The cause of a trip, the intended forced outage work scope, or outage duration varies and inevitably will factor into which method of normal long term heat removal is best for the station to employ shortly following a trip.</p> <p><b>Response:</b> The ROP working group is currently working to prepare a response. <b>Licensee Proposed Response:</b> NO. Since vacuum was secured at the discretion of the Shift Supervisor and could have been restored using existing normally performed operating procedures, the function meets the intention of being available but not used.</p>		
36.1	IE02	<p><b>Question:</b></p> <p>With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIV's to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam).</p> <p>At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig.</p> <p>Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low.</p> <p>Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser.</p> <p>As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump.</p> <p>The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event.</p> <p>Does this scram constitute a scram with a loss of normal heat removal?</p>	9/25 Introduced and discussed	Quad Cities

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		<p><b>Response:</b>            No. The normal heat removal path was not lost even though the MSIVs were manually closed to control cooldown rate. There was no leak downstream of the MSIVs, and reopening the MSIVs would not have introduced further complications to the event. The normal heat removal path was purposefully and temporarily isolated to address the cooldown rate, only. Reopening the normal heat removal path was always available at the discretion of the control room operator and would not have involved any diagnosis or repair.</p> <p><b>Further supporting information:</b>            The clarifying notes for this indicator state: "<i>Loss of normal heat removal path</i> means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is <i>available</i>, not whether the operators choose to use that path or some other path." In this case, the operator did not choose to use the path through the MSIVs, even though the normal heat removal path was available.            The clarifying notes for this indicator also state: "<i>Operator actions or design features to control the reactor cooldown rate or water level</i>, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair." In this case, the closing of the MSIVs was performed solely to control reactor cooldown rate. It was not performed to isolate a steam leak. There was no diagnosis or repair involved in this event. The MSIVs could have been reopened following normal plant procedures</p>		
36.2	IE02	<p><b>Question:</b>            Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation?</p> <p><b>Description of Event:</b>            At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours.            At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel II high Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV). Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored.            At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including: stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps.</p> <p><b>Problem Assessment:</b>            It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the</p>	9/25 Introduced and discussed	Peach Bottom

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		<p>cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs.</p> <p>Reopening of the MSIVs was:</p> <ul style="list-style-type: none"> <li>• easily facilitated by restarting Reactor Building ventilation,</li> <li>• completed from the control room using normal operating procedures</li> <li>• without the need of diagnosis or repair</li> </ul> <p>Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.</p> <p><u>Discussion of specific aspects of the event:</u></p> <p>Was the recognition of the condition from the Control Room?</p> <ul style="list-style-type: none"> <li>• Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room.</li> </ul> <p>Does it require diagnosis or was it an alarm?</p> <ul style="list-style-type: none"> <li>• The event is annunciated in the control room as described previously.</li> </ul> <p>Is it a design issue?</p> <ul style="list-style-type: none"> <li>• Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3.</li> </ul> <p>Are actions virtually certain to be successful?</p> <ul style="list-style-type: none"> <li>• The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required.</li> </ul> <p>Are operator actions proceduralized?</p> <ul style="list-style-type: none"> <li>• The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room.</li> </ul> <p>How does Training address operator actions?</p> <ul style="list-style-type: none"> <li>• The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training.</li> </ul> <p>Are stressful or chaotic conditions during or following an accident expected to be present?</p> <ul style="list-style-type: none"> <li>• As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions</li> </ul>		

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		<p><b>Response:</b>            The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.</p>		
36.8	IE02	<p><b>Question:</b>            On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?"</p> <p><b>Response:</b>            No. Under clarifying notes, page 16, lines 18 - 22, NEI 99-02 states: "Actions or design features to control the reactor cool down rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported." In this case, a feedwater isolation signal had automatically closed the main feed regulating valves, effectively mitigating the high level condition. Manually closing the MSIVs was a conservative procedure driven action, which in this case was not by itself necessary to protect personnel or equipment. The main feed regulating valves were capable of being easily opened from the control room, and the MSIVs were capable of being opened from the control room (after local action to bypass and equalize pressure, see FAQ 303).</p> <p>In addition, the cause of the high steam generator level was due to voltage fluctuations on the offsite power grid which resulted in the operators closing the MSIVs. Clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power. In this case, offsite power was not lost. However, the disturbances in grid voltage affected the ADFCS system which started a chain of events which ultimately resulted in the closure of the MSIVs.</p>	1/22 Introduced 3/25 Discussed	Ginna
36.9	IE02	<p><b>Question:</b>            During startup activities following a refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations began to increase as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main</p>	1/22 Introduced 3/25 Discussed. Question to be rewritten and response provided 4/22 Question and response provided	Millstone 2

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		<p>feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators.</p> <p>Based on industry operating experience, operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage Licensed Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34) for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience.</p> <p>Does a SCRAM in which the normal heat removal path is manually isolated in accordance with normal plant procedures for protection of non-safety plant equipment count against this indicator?</p> <p><b>Response:</b></p> <p>No, this scram does not count against the performance indicator for scrams with loss of normal heat removal. The conditions that resulted in the closure of the MSIVs after the reactor trip were expected for the main turbine startup following rotor replacement. Operator actions for this situation had been incorporated into <u>normal plant procedures</u>.</p>		
37.3	OR1	<p><b>Question:</b></p> <p>It was determined that a physical barrier being used to control access to a high radiation area (greater than 1000 mrem per hour) could easily be circumvented. However, to circumvent the controls that were in place would require an intentional act. An example of this might include one of the following:</p> <ol style="list-style-type: none"> <li>1. Fencing used as a barrier at the boundary of the high radiation area was not firmly secured (i.e., loosely secured, or just taped to a wall) such that an individual could, by hand, create an opening large enough to pass through.</li> <li>2. The barrier was constructed of a material that could easily be breached with a pocket knife (i.e., thin plastic sheeting or webbing).</li> <li>3. An individual could pass their hand through the barrier and open the locked door to the area from the inside.</li> <li>4. The barrier is a short fence (&lt;6 foot high), or hand rail, such that an individual could step over, climb over, or crawl under, with little-to-moderate effort.</li> <li>5. A locked gate is provided at the top of a ladder to control access to a high radiation area on a lower level of the plant. However, by stepping around (or over) the gate, an individual can still access to the rungs of the ladder.</li> </ol> <p>Since the controls in place, as described above, were adequate to prevent an inadvertent entry (i.e., accidental or unintentional entry by an individual not paying sufficient attention), and the definition of terms on page 98 in NEI 99-02 Rev. 2, refers to "measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel," is this a (or are these) reportable PI occurrence(s)? How about if this were a very high radiation area (&gt;500 rads per hour)?</p> <p><b>Response:</b></p> <p>The first example on page 99 of NEI 99-02, Rev.2, clearly states that the failure to secure a high radiation area (&gt;1000 mrem per hour) against unauthorized access is a reportable PI occurrence. Since the physical barriers provided for each of these areas can be easily circumvented (i.e., did not secure the area), they would each be a PI occurrence. The term "inadvertent entry" on page 98 of NEI 99-02, is used in the sense that the violation of the regulatory requirement (e.g., resulting from the unauthorized entry) was unintended, as opposed to whether the act</p>	<p>3/25 Introduced 4/22 Directed to HP counterparts for review 5/27 To be revised by HP counterparts</p>	NRC

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		itself was accidental or unintended. As used here, an unintentional violation could be a non-flagrant, intended, act resulting from a misunderstanding as to the existence the requirement, the meaning of the requirement, or that the action conformed to the requirement. If the unauthorized entry was an intended violation of the regulatory requirement, this would be a willful violation subject to normal NRC Enforcement Policy. A willful violation is outside the scope of this Performance Indicator.		
37.4	IE03	<p><b>Question:</b>            During a scheduled refueling outage, the rotor was replaced on the 'C' low pressure turbine. During initial startup on October 27, 2003, with the plant stable at 17.7% reactor power, high vibrations were detected on the bearings associated with the replaced rotor. The turbine was tripped and shutdown, a troubleshooting team formed and a repair plan developed. In order to collect vibration data required to identify the optimum location for the placement of balancing weights, the repair plan called for the starting and phasing of the main turbine. With reactor power at 22.2%, the main generator breaker was closed at 18:32. After the collection of vibration data, the turbine was tripped at 20:37 and reactor power reduced to 1.1%. When the performance indicator data for the 4th quarter of 2003 was submitted, this reduction in power of 21.1% was not included in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator.</p> <p>The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Frequently, high vibrations and/or rubbing occur during startup following rotor replacement. As an expected condition rather than an off-normal condition, the associated reduction in power should not count as an unplanned power change.</p> <p><b>Is the power change described above considered an unplanned power change for performance indicator reporting?</b></p> <p><b>Response:</b>            Yes. The plant did not anticipate the vibration problem and the potential need to downpower in its procedures.</p>	3/25 Introduced 4/22 Need additional information 5/27 Tentative approval. Response to be revised.	Seabrook
37.5	OR1	<p><b>Question:</b>            A worker entered a Technical Specification High Radiation Area (&gt; 1R/hr) with all requirements of the job (training, briefings, dosimetry, ALARA Plan and RWP requirements, electronic dosimetry, etc.). The worker did not perform the RWP process auto-sign-in on the RWP, which would have electronically checked the worker's 700 mrem administrative RWP buffer. Not performing this auto-sign-in process did not violate the primary means of controlling access and did not invalidate the RWP for the job. The RWP stated that 700 mrem dose availability was required prior to entry. This administrative dose buffer is an additional defense-in-depth, licensee-initiated control to protect against exceeding the licensee's system of dose control and is not utilized to control dose. The worker's actual dose did not exceed the electronic dosimeter set point and the minimum administrative control guideline. The dose availability of the worker is defined as the difference between the site-specific administrative control level of 2000 mrem (significantly below Federal Limits) and the worker's current accumulated dose for the year.</p> <p>An ALARA Plan and RWP controlled the work activity. The individual used teledosimetry with predetermined alarm setpoints for the job, which transmitted dose and dose rate information during the entry. Video surveillance was utilized by radiation protection technicians and in compliance with 10CFR20.1601(b) during the entry into the &gt;1R/hr area. Specific authorization was given by the remote monitoring station technician to enter into the area. The worker had the training and respiratory protection qualifications required by the RWP, multiple TLDs had been issued, the required RWP was obtained and signed, and briefings were attended. The RWP entry was accomplished within pre-determined stay-time limitations, as discussed in the worker briefing. The electronic entry time was entered after the worker had exited the area. There was no over exposure or unintended dose for this worker. The work was completed within the maximum projected dose for the activity. Technical Specification requirements for</p>	3/25 Introduced 4/22 Being revised by licensee 5/27 Revised To be reviewed by HP counterparts	TMI

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		<p>control of entry into the high radiation area were met and worker dose was controlled since the worker was authorized and had obtained the RWP for the job.</p> <p>The primary means of control of occupational dose exposure include pre-determined stay-time limitations and alarming dosimetry set below expected job levels. The administrative control level is an additional exposure control mechanism. The licensee's administrative control level is conservatively established at 2 rem, or 40% of the Federal dose limit, to provide a substantial margin to prevent personnel from exceeding the Federal dose limit of 5 rem and to help ensure equitable distribution of dose among workers with similar jobs. The individual's annual dose was well below 2 rem and the administrative control level had not been raised above 2 rem prior to the worker obtaining a TLD. If needed, additional and higher levels of managerial review and authorization are required for higher dose control levels. Increasing levels of management review and approvals are required to exceed the administrative control level of 2000 mrem (i.e., to 3000 mrem requires written approval by the Radiation Protection Manager and the work group supervisor, to 4000 mrem requires written approval by the Radiation Protection Manager, work group supervisor, and Plant Manager, to 5000 mrem requires written approval by the Site Vice President). The administrative dose buffer is in addition to the Technical Specification requirements for an RWP and therefore not material to the Technical Specification requirements for control of occupational dose.</p> <p>As it is stated in NEI 99-02, "this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10CFR Part 20." The check of dose availability is a licensee-initiated administrative control that is beyond what is required by technical specifications, comparable provisions in 10CFR20, or Regulatory Guide 8.38. Does failure of the worker to meet the internal administrative control guideline for dose available as specified by the RWP for the job activity count as a PI occurrence?</p> <p><b>Response:</b> No, this event constitutes a procedural failure to meet a licensee-initiated administrative control; however, this event would not be a PI occurrence. Such an event would be reviewed under the appropriate NRC inspection criteria.</p>		
37.6	BI02	<p><b>Question:</b> River Bend Station (RBS) seeks clarification of BI-02 information contained in NEI 99-02 guidance, specifically page 80, lines 36 and 37 "<i>Only calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator.</i>"</p> <p>NEI 99-02, Revision 2 states that the purpose for the Reactor Coolant System (RCS) Leakage Indicator is to monitor the integrity of the reactor coolant system pressure boundary. To do this, the indicator uses the identified leakage as a percentage of the technical specification allowable identified leakage. Moreover, the definition provided is "the maximum RCS identified leakage in gallons per minute each month per technical specifications and expressed as a percentage of the technical specification limit."</p> <p>The RBS Technical Specification (TS) states "Verify RCS unidentified LEAKAGE, total LEAKAGE, and unidentified LEAKAGE increase are within limits (12 hour frequency)." RBS accomplishes this surveillance requirement using an approved station procedure that requires the leakage values from the 0100 and 1300 calculation be used as the leakage "of record" for the purpose of satisfying the TS surveillance requirement. These two data points are then used in the population of data subject to selection for performance indicator calculation each quarter (highest monthly value is used).</p> <p>The RBS approved TS method for determining RCS leakage uses programmable controller generated points for total</p>	3/25 Introduced 4/22 Discussed 5/27 Discussed	River Bend

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		<p>RCS leakage. The RBS' programmable controller calculates the average total leakage for the previous 24 hours and prints a report giving the leakage rate into each sump it monitors, showing the last four calculations to indicate a trend and printing the total unidentified LEAKAGE, total identified LEAKAGE, their sum, and the 24 hour average. The programmable controller will print this report any time an alarm value is exceeded. The printout can be ordered manually or can be automatic on a 1 or 8 hour basis. While the equipment is capable of generating leakage values at any frequency, the equipment generates hourly values that are summarized in a daily report.</p> <p>The RBS' TS Bases states "In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends."</p> <p>The Licensee provides that NEI 99-02 requires only the calculations performed to accomplish the approved TS surveillance using the station procedure be counted in the RCS leakage indicator. In this case, the surveillance procedure captures and records the 0100 and 1300 RCS leakage values to satisfy the TS surveillance requirements. The NRC Resident has taken the position that <u>all</u> hourly values from the daily report should be used for the RCS leakage performance indicator determination, even though they are not required by the station surveillance procedure. The Resident maintains that all hourly values use the same method as the 0100 and 1300 values and should be included in the leakage determination.</p> <p>Is the Licensee interpretation of NEI 99-02 correct?</p> <p><b>Response:</b> Yes. It was never the intent of the guidance to require all leakage determinations to be used for this performance indicator. Only those calculations that are performed to meet the requirements of the technical specification surveillance should be considered.</p>		
37.9	EP02	<p>Question: NEI 99-02 Rev 2 ERO Participation PI defines the numerator and denominator of the calculation as based on Key ERO Members. The list was originally created from the NUREG-0654 Table B-1 positions that involved actions associated with the risk significant planning standards (classification, notification, PARS, and assessment), with the addition of the Key OSC Operations Manager included from a mitigation perspective.</p> <p>It is understood that when a single individual is assigned in more than one 'key position' they must be counted individually for each position (page 91 lines 4-7 of NEI 99-02).</p> <p>Guidance is not provided in the case where key positions are not unique to separate ERO members. For example, the communicator is defined in NEI 99-02 as the individual that fills out the notification form, seeks approval and usually communicates the information to off site agencies (these duties may vary from site to site based on site procedures). When the communicator activity is performed by an ERO member who is also defined by another key position (i.e., the Shift Manager), should participation be counted individually for each function or collectively for the single member?</p>	4/22 Introduced 5/27 Discussed. To be revised to reflect discussion.	generic

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		<p><b>Response:</b>  Yes, participation should be counted as individual opportunities for each key ERO function, even when the key ERO function is performed by the same qualified ERO member. In the case where a utility has combined the functions of the qualified ERO members as defined in the NEI guidance under a single position, those key ERO functions must be counted as separate opportunities in the denominator for each qualified ERO member and credit given in the numerator when the qualified ERO member performs each individual key ERO function.</p> <p>This indicator provides linkage to the DEP PI, measuring the individuals who have performed the key ERO function over all of the assigned qualified ERO members. Assigning a single member to multiple functions and then only counting the performance for one function could mask the ability or proficiency of the remaining functions. The concern is that an ERO member having multiple functions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple functions is performed; particularly, if more than one ERO position is assigned to performed the same function.</p>		
38.1	MS01	<p><b>Question:</b>  This FAQ seeks clarification of the guidance in NEI 99-02 regarding fault exposure. Specifically, NEI 99-02, page 30, lines 3-6 describe fault exposure (T) in terms of failure and the failure's known time of occurrence and known time of discovery. Lines 13-20 provide "T/2" fault exposure guidance where the time of failure is uncertain and only the time of discovery is known. This clarification will be used to determine whether a situation is "T" or "T/2." Emergency diesel generator "A" (EDG A) failed a monthly surveillance on September 29, 2003. A fuel oil line connection on the diesel failed during the surveillance; the surveillance was halted and the diesel declared inoperable. Based upon guidance in NEI 99-02 and FAQ 318, the plant reported in the 3Q03 performance indicator submittal T/2 fault exposure hours based upon the time from the last successful surveillance (September 2, 2003) until EDG A failed on September 29, 2003. This is due largely to the guidance that notes "...Fault exposure hours for this case must be estimated. The value used to estimate the fault exposure hours for this case is: one half the time since the last successful test or operation that proved the system was capable of performing its safety function." Is this interpretation of the guidance correct?</p> <p><u>Additional Details:</u>  A root cause determined that plant maintenance introduced a latent condition on May 16, 2003 during maintenance on the diesel that lead to EDG A failure during the September 29 surveillance. The root cause established the failure mechanism was fatigue. A time of failure after the introduction of the latent maintenance condition cannot be predicted with certainty because of the complexity of the fatigue phenomenon e.g., fatigue failure is a non-linear function of time; it is also cumulative. The fatigue failure was further complicated by multiple starts and stops of the diesel during monthly surveillances. (From the time the tubing was installed in May 2003, EDG A ran for almost 29 hours over a period of about 4 months and 5 successful surveillances.)  NRC inspection noted "the finding is a potential reporting error concerning the Emergency AC Power System Unavailability performance indicator," i.e., that T fault exposure hours should apply based upon the time of the maintenance in May until the diesel was returned to service in September.</p> <p><b>Response</b>  For this situation, the Licensee interpretation is correct that T/2 should apply. The fatigue failure mechanism for this case is sufficiently uncertain such that the loss of safety function cannot be predicted with certainty prior to the last successful surveillance of the diesel. It should be noted that reporting T/2 hours ensures that NRC is aware of a failure that potentially warrants inspection; this situation has been inspected.</p>	4/22 Introduced 5/27 Discussed	Waterford
38.2	MS01, MS04	<p><b>Question:</b>  If the emergency AC power system or the residual heat removal system is not required to be available for service (e.g., the plant is in "no mode" or Technical Specifications do not require the system to be operable), is it appropriate</p>	5/27 introduced	

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		<p>to include this time in the "hours train required" portion of the safety system performance indicator calculation?</p> <p>NEI 99-02, Revision 2, starting on line 25 of page 33, discusses the term "hours train required" as used in safety system unavailability performance indicators. For the emergency AC power system and residual heat removal system, the guidance allows the "hours train required" to be estimated by the number of hours in the reporting period because the emergency generators are normally expected to be available for service during both plant operations and shutdown, and because the residual heat removal system is required to be available for decay heat removal at all times.</p> <p>The response to FAQ 183 states: "During periods and conditions where Technical Specifications allow both shutdown cooling trains to be removed from service the shutdown cooling system is, in effect, not required and required hours and unavailable hours would not be counted."</p> <p><b>Response:</b>  <b>NRC:</b>  During periods and conditions where Technical Specifications allow all trains of a system to be removed from service the system is, in effect, not required and required hours and unavailable hours would not be counted  <b>Industry:</b>  FAQ 183 referred to plant specific technical specifications of an RHR system, and was listed in NEI 99-02 Rev 1. Appendix E, "Frequently Asked Questions," as an Appendix D (plant specific) FAQ. The text of NEI 99-02 was not changed in either Rev 1 or 2 to apply this answer to all plants. It also did not apply to Emergency Diesel Generators. On a going forward basis, however, during periods and conditions when Technical Specifications allow all trains of a system to be removed from service, the system is in effect not required and required hours and unavailability hours would not be counted. Rev. 3 of NEI 99-02 will be modified to incorporate this change in guidance.</p>		
38.3	MS01	<p><u><a href="#">Appendix D FAQ: Mitigating Systems – Safety System Unavailability, Emergency AC Power</a></u></p> <p>During a monthly surveillance test of Emergency Diesel Generator 3 (EDG3), an alarm was received in the control room for an abnormal condition. The jacket water cooling supply to EDG3 had experienced a small leak (i.e., less than 1 gpm) at a coupling connection that resulted in a low level condition and subsequent control room alarm. The Low Jacket Water Pressure Alarm, which annunciates locally and in the control room, indicated low pump suction pressure. This was due to low level in the diesel generator jacket water expansion tank. An Auxiliary Operator (AO) stationed at EDG3 responded to the alarm by opening the manual supply valve to provide makeup water to the expansion tank. EDG3 continued to function normally and the surveillance test was completed satisfactorily.</p> <p>Review of data determined that improper tightening of the coupling was performed after the monthly EDG run on December 8, which led to an unacceptable leak if the EDG was required to run. The coupling was properly repaired and tested, and declared to be available and operable on January 6. The condition existed for approximately 28 days. Although the recovery action was conducted outside of the main control room, it was a simple evolution directed by a procedure step, with a high probability of success. This operator response is similar to the response described in Appendix D FAQ 301. In addition, this operator action would be successful during a postulated loss of offsite power event, except for a 23 hour period when the demineralized water supply level was too low to support gravity feed. The engineering analysis determined that a level of 21' 5" of demineralized water supply level was necessary to support gravity feed to the expansion tank. Another 9" (4,740 gallons) was added to this level to allow for the leak and nominal usage and makeup over the 24 hour mission time. Using this analysis, any time the demineralized water level fell below 22' 2", the EDG was considered to be unavailable. A human reliability analysis calculated the probability of an AO failing to add water to the expansion tank from receipt of the low pressure alarm to be 4.7 E-3. In other words, there would be a greater than 99.5% probability of successful task completion within twenty minutes of receiving the annunciator. Vendor analysis determined that, with the existing leak rate, the EDG would remain</p>	6/16/04 Introduced	Brunswick

TempNo.	PI	Question/Response	Status	Plant/ Co.
		<p><u>undamaged for twenty minutes.</u></p> <p>The human reliability analysis considered that the low jacket water pressure would be annunciated in the control room, the annunciator procedure provided specific direction for filling the expansion tank, the action is reinforced through operator training, and sufficient time would be available to perform the simple action. In its calculation of the probability of operator recovery, the analysis also considered that another indicator, a low-level expansion tank alarm was out-of-service during this time period. However, although the low expansion tank alarm was out of service, it results in low pump suction pressure which did annunciate.</p> <p>NEI 99-02 Appendix D lists several issues that may be addressed for exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems.</p> <ol style="list-style-type: none"> <li>1. The capability to recognize the need for compensatory actions – Low pump suction pressure annunciates in the control room.</li> <li>2. The availability of trained personnel to perform the compensatory action – This is an uncomplicated action, but operators are trained on it. An auxiliary operator simply has to open one manual valve as directed by the annunciator procedure.</li> <li>3. The means of communications between the control room and the local operator – Communications can be accomplished either via the plant PA system or a portable radio.</li> <li>4. The availability of compensatory equipment – No compensatory equipment is necessary.</li> <li>5. The availability of a procedure for compensatory actions – There is an annunciator procedure in the diesel generator room that would direct the auxiliary operator to open the manual valve.</li> <li>6. The frequency with which the compensatory actions are performed – This action is performed infrequently, but it was demonstrated to be successful during the surveillance test.</li> <li>7. The probability of successful completion of compensatory actions within the required time – The human reliability analysis determined that there was a 99.5% probability of successful completion of compensatory action within the required time.</li> </ol> <p>In summary, over a 28-day period, jacket water cooling for EDG3 was degraded, but functional for approximately 27 days, and was totally unavailable for 23 hours. This is based on a review of Operator logs, plant trending computer points, and flow calculations. During the 27-day degraded period, a simple manual action directed by procedure and performed by an operator would have been used to ensure that jacket water was available. Should fault exposure hours be reported for the 27 days when the Emergency Diesel Generator 3 jacket water was considered to be degraded but functional?</p> <p><b>Response:</b>  <u>No. Unavailable hours need not be reported for this situation. The actions are proceduralized, operators are trained on the procedure, no troubleshooting or diagnosis is necessary, there is a control room alarm to alert the operators to the need for action, and the actions have been demonstrated to be able to be accomplished within the necessary time constraints. Therefore, operator recovery actions are considered to be virtually certain of success.</u></p>		

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38.4	EP03	<p><b>Question:</b></p> <p>Pilgrim has 112 sirens which are normally scheduled to be tested for performance indicator purposes once each calendar month (e.g., once during the month of September). This was reflected in procedure as a requirement to test all of the sirens "monthly". The person scheduling the testing of the sirens incorrectly interpreted the procedure's "monthly" frequency consistent with other "monthly" tests as allowing a 25% grace period for scheduling flexibility. As a result, 29 of the siren tests normally scheduled to be performed in September were scheduled to be performed during the beginning of October.</p> <p>On October 1 the status of the siren testing was discussed with other members of the plant staff who understood that the intent of the "monthly" requirement was once per calendar month and that no grace period applied. Immediate actions were taken including performing the remaining 29 tests on an accelerated basis (all satisfactory tested by October 3) and entering the item in the corrective action program.</p> <p>All of the 29 sirens passed the testing performed during the first 3 days of October. The testing was not delayed due to the unavailability or suspected unavailability of the sirens. The reason for the late testing of the equipment was purely an administrative error and not siren functionality related.</p> <p>For plants where siren tests are initiated by the utility, if a scheduled test(s) was not performed due to an administrative issue but the untested siren(s) was not out-of-service for maintenance or repair and was believed to be capable of operation if activated, should the missed tests be considered non-opportunities or failures for performance indicator reporting purposes?</p> <p><b>Response:</b></p> <p>Tests missed for reasons other than siren unavailability (e.g., out of service for maintenance or repair) should be considered non-opportunities</p>	6/16/04	Pilgrim

**REACTOR OVERSIGHT PROCESS**  
**WORKING GROUP ACTION LIST – June 2004**

The following is the current listing of action items (“take aways”):

OPEN Action Items	Description	Due Date
04-01	<p><b>RCS Leakage PI (B02)</b></p> <p><u>Task:</u> NRC – Evaluate the feasibility of modifying or replacing the existing barrier integrity Pls. Respond to industry comments on the draft RCS Leakage PI paper, and provide comments.</p> <p><u>Status:</u> Issue is evolving. NRC has Davis-Besse lessons learned action items to develop potential alternative leakage PI algorithms. Carry as an agenda item to monitor until resolved. A sub-group (BWRs/PWRs) to evaluate potential new areas (RCS pressure boundary degradation) is being considered. NEI to provide feedback from Owner Group meetings, and the sub-group task is to develop an obtainable goal. NRC to provide list of potential attendees for the groups.</p>	<i>Open</i>
04-05	<p><b>Safety System Functional Failure (MS05) Reconciliation Project</b></p> <p><u>Task:</u> NRC provided the docket number and corresponding Licensee Event Reports (LER) for which the NRC's contractor assessed the LER as being a Safety System Functional Failure (SSFF: MS05). Industry is reviewing this data against ROP reported data and will provide an analysis of differences.</p> <p><u>Status:</u> Initial review of all contractor LER-evaluations complete; results provided to individual licensees for reconciliation/additional-information. Licensee feedback being evaluated.</p>	8/31/04
04-07	<p><b>NRC Comments on Generic Changes in NEI 99-02 (Revision 3)</b></p> <p><u>Task:</u> NRC to provide a listing of sections within NEI 99-02 Rev 2 that contain ambiguous or unclear guidance that the NRC has identified as needing modification when drafting Rev 3 by March meeting. This is to be subsumed within 04-16 when NRC comments received.</p> <p><u>Status:</u> NRC still working on developing comments.</p>	7/15/04
04-09	<p><b>Maintenance Rule Workshop</b></p> <p><u>Task:</u> NRC is considering holding a workshop on the new Maintenance Rule SDP. Doug Coe will go over the issues raised by industry, and determine whether a meeting is appropriate. Decision whether a workshop would be appropriate will be made in several months.</p> <p><u>Status:</u> Open- Doug Coe to determine if workshop is necessary.</p>	07/15/04
04-11	<p><b>Revised FAQ Process</b></p> <p><u>Task:</u> Provided NRC with current draft of FAQ process.</p> <p><u>Status:</u> Discussed the difference of opinion on the mechanism for resolving FAQ disputes. NRC to provide initial comments on guidance on new FAQ process and provide feedback via email. Industry provided a rough second draft for further review/comment by July SPATF meeting.</p>	07/15/04
04-12	<p><b>Replacement Metric for SCRAMS wlonhr (IE02)</b></p> <p><u>Task:</u> NRC and Industry to develop a proposed replacement indicator for existing IE02 metric.</p>	

<b>OPEN</b>	<b>Action Items</b>	<b>Description</b>	<b>Due Date</b>
		<p><u>Status:</u> NRC provided a draft purpose statement, and Industry will review and come back at the July meeting with comments. At the July meeting, we will discuss formation of a subgroup to work on these concerns.</p>	OPEN
04-13	<b>Fire Protection SDP Review</b>	<p><u>Task:</u> NRC Review process for fire protection SDPs has no apparent feedback (to licensees) provided from the NRC panel meetings.</p> <p><u>Status:</u> Review process on the Fire Protection SDP panel and determine (and report back) how will have feedback provided from the panel meetings.</p>	06/15/04
04-16	<b>NEI 99-02 Revision 3</b>	<p><u>Task:</u> NEI (Tom Houghton) to provide a consolidated "for comment draft" (for further review/comment) by the July meeting. The overall goal will be to develop a final Rev3 by November 2004.</p> <p><u>Status:</u> Open</p>	07/31/04
04-17	<b>Mitigating Systems Performance Index</b>	<p><u>Task:</u> NRC Commission has directed the NRC staff to work together with industry to resolve the issues associated with the MSPI.</p> <p><u>Status:</u> NRC to compile all additional internal stakeholder comments (not discussed in SECY 04-0053) and provide to NEI by next meeting.</p>	07/20/04
04-18	<b>Licensee Identified versus Self-Revealing Events</b>	<p><u>Task:</u> NRC to evaluate the MC 0612 criteria on "self identified" versus "self-revealing"</p>	07/20/04
04-19	<b>Resolution of old IE02 FAQs</b>	<p><u>Task:</u> Discussed the seven FAQs (27.3, 28.3, 30.8, 32.3a, 34.6, 36.1, and 36.2) which involve SCRAMS with loss of normal heat removal. Identified that NEI has reviewed the respective inspection report which examined the particular SCRAM. Industry had proposed in the April meeting that NRC consider dropping these FAQs since (1) they involve specific conflicting guidance in NEI 99-02; (2) the issue is typically over 3 years old and is now moot; and (3) additional information is in several of the NRC inspection reports involving recoverability of systems (new information). NRC agreed to review the NEI data and come to the July meeting with a decision on whether to drop some/all of these FAQs or to dedicate time at the July meeting to re-examine each of these FAQs and make a final recommendation.</p>	07/20/04

<b>CLOSED</b> Action Items		Description	Due Date
04-02	<b>Steam Generator SDP</b> <u>Task:</u> INDUSTRY– Provide examples of “minor” steam generator issues/results/findings by the March meeting		<i>Closed</i>
	<u>Status:</u> Examples provided and NRC to include appropriate examples in MC 0612 Appendix E.		
04-03	<b>Maintenance Rule SDP</b> <u>Task:</u> Provide written comments on the Maintenance Rule SDP by the March meeting. <u>Status:</u> Example/comments provided and NRC to include in final SDP.		<i>Closed</i>
04-04	<b>SDP Lessons Learned</b> <u>Task:</u> NRC and Industry brought SDP timeliness examples to the meeting. Industry to evaluate these examples for inclusion as case studies in an SDP workshop devoted to improving SDP timeliness. Industry to review schedule to support a summer workshop. <u>Status:</u> Workshop targeted for mid-July. NRC to confirm dates and NEI to send out letter to APCs announcing workshop. Rescheduled for September.		<i>Closed</i>
04-06	<b>Graded Reset of Action Matrix Inspection Findings</b> <u>Task:</u> NRC to provide the resolution (answer) to the graded reset question raised by Industry by the March meeting and in FRN comments on the ROP. <u>Status:</u> NRC provided response. While closed, Industry intends to continue to pursue via other channels.		<i>Closed</i>
04-08	<b>Industry Trends Report</b> <u>Task:</u> NRC will provide the Industry Trends Report when available. <u>Status:</u> Received		<i>Closed</i>
04-10	<b>Ginna FAQ</b> <u>Task:</u> Licensee to review their previous FAQ and determine if their closing of the MSIVs (early on in the post trip recovery) is still applicable, or if their process has changed and the FAQ is no longer appropriate to apply [Licensee responded that the process has not changed – Open for discussion in May meeting]. <u>Status:</u> Licensee has provided input To be discussed at June ROP meeting		<i>Closed</i>
04-14	<b>NRC FAQ Feedback Process</b> <u>Task:</u> NRC to examine their internal feedback form process and how it should be included in the FAQ process. <u>Status:</u> NRC has agreed to initiate FAQs for all NRC feedback forms related to NEI 99-02 interpretation issues. This item will be folded into Action 04-11 upon completion of draft FAQ process.		<i>Closed</i>
04-15	<b>Mitigating Systems Pls – No Mode</b> <u>Task:</u> NRC to prepare an FAQ on how to account for “No Mode” hours in MS04 PI. <u>Status:</u> This would be a going forward FAQ.		<i>Closed</i>

## MSPI Implementation Tasks

- 1) Develop and Implement CDE software changes
- 2) Develop Access version of CDE software for use during implementation until CDE up
- 3) Sample Bases Documentation
- 4) Develop final Guidance Documents
  - a) NEI 99-02
- 5) Revise and Endorse Maintenance Rule guidance
  - a) NUMARC 93-01 Revision 4
  - b) Regulatory guide 1.???????
- 6) Develop Industry Communication Plan
- 7) Develop NRC Communication Plan
- 8) Plan and Conduct workshops
  - a) Determine Location and dates
  - b) Develop training material
- 9) Develop and implement Inspection Plan
  - a) System Scope Definitions
  - b) Initial Data Conversion (SSU to MSPI)
  - c) PRA information
  - d) PRA adequacy
- 10) Define and conduct further pilot activities
  - a) Common cause inclusion