This document contains FAQs that were approved since the last revision of NEI 99-02.
The following table has the most recently approved FAQs toward the top of the list.

Database #	FAQ #	PI	Site-Specific (SS) or Generic (G)	Subject	Effective Date
TBD	14-04	OR01	Generic	Concurrent Failures	09/11/14
TBD	14-01	MS06 MS07 MS08 MS09 MS10	Generic	MSPI PRA Technical Adequacy	18 months after approval or completion of a licensee's next periodic update of their PRA model and associated basis document update following approval, whichever is later.
TBD	13-07	EP01	Generic	DEP Scoring Opportunity	04/01/14 Final on 01/15/14
TBD	13-05	IE03	Oyster Creek (G)	Downpower	04/02/14
TBD	13-04	EP03	Point Beach (SS)	ANS	04/02/14
TBD	13-06	MS07	Dresden (G)	HPCI Failure	01/15/14
TBD	13-03	IE03	Quad Cities (G)	Animal Intrusion/Power Change	11/20/13
TBD	13-02	IE03	Susquehanna (G)	Power Change	10/23/13
TBD	13-01	IE01	Turkey Point 3 (SS)	Exemption Request from Green-White Threshold	06/26/13
TBD	12-04	OR01	Perry (G)	HRA Related Occurrences	5/13/2013
TBD	12-05	MS05	Browns Ferry (G)	Counting Additional Failures	(Withdrawn) 01/17/2013

FAQ 14-04 (Final)
Definition of Concurrent Failures

Plant: Generic
Date of Event: NA
Submittal Date: July 16, 2014
Contact: James Slider **Tel/email:** (202) 739-8015, jes@nei.org
NRC Contact: Luis Cruz **Tel/email:** (301) 415-3982, luis.cruz@nrc.gov

Performance Indicator: OR01, Occupational Exposure Control Effectiveness

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: When approved.

Question Section

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

Rev. 7, "Clean" copy, page 64, footnote 14 below line 40:

14 "Concurrent" means that the nonconformances occur as a result of the same cause and in a common timeframe.

Event or circumstances requiring guidance interpretation:

The resolution of Reaction Oversight Process FAQ 12-04 required development of a revision to a footnote in the section on Occupational Exposure Control Effectiveness (OR01). In Revision 7 of NEI 99-02, the crucial footnote is number 14 on page 66 of the line-in/line-out version, which reads as follows:
"Concurrent" means that the nonconformances occur as a result of the same cause and in a common timeframe."

What is the NRC resident inspector's position?

NA. This FAQ implements a White Paper approved by the ROP Working Group.

Potentially relevant existing FAQ numbers

FAQ 12-04 was the trigger for the White Paper.

Response Section

Proposed Resolution of FAQ:

See approved new wording below.

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

As a result of numerous discussions on the meaning and original intent of "concurrent nonconformances" during the resolution of FAQ 12-04, the following is the proposed new text of Footnote 14:
"Concurrent" means that the nonconformances occur as a result of the same cause and in a common timeframe. Failing to take reasonable action that would end a nonconformance when new information (i.e., a survey indicates, or a knowledgeable individual finds evidence of, unidentified or unexpected radiological conditions) is presented, is itself a new and separate cause for the subsequent (or continued) Tech. Spec. nonconformance, and would not be concurrent with the original Technical Specification High Radiation Area Occurrence."

Is a PRA update required to implement this FAQ?

No

FAQ 14-04 (Final)
Definition of Concurrent Failures

Is an MSPI Basis Document update required to implement this FAQ?
No

NRC Response
This FAQ incorporates the definition of "concurrent failures" approved by the ROP Working Group through the white paper on the definition of "concurrent failures" (ADAMS Accession No. ML14041A251). The final approved wording of the change in NEI 99-02, Rev. 7, to implement the White Paper is as follows:

Footnote 14:` "Concurrent" means that the nonconformances occur as a result of the same cause and in a common timeframe. Failing to take an action that would have reasonably ended a nonconformance is itself a new and separate cause for the subsequent (or continued) Technical Specification nonconformance and would not be concurrent with the original Technical Specification High Radiation Area Occurrence. Actions that would reasonably end a nonconformance include performing a plant procedure (e.g., a radiation survey, or a verification that Locked High Radiation Area is locked) that would have identified the plant condition, or responding in a timely manner to new information (e.g., the results of a radiation survey, or evidence of the nonconforming radiological condition that is identified by a knowledgeable individual) that indicates the nonconformance.

Plant: Generic
Date of Event: N/A
Submittal Date: May 14, 2014
Licensee Contact: PWROG RMSC **Tel/email**: roy.linthicum@exeloncorp.com
NRC Contact: Stephan Vaughn **Tel/email:** @nrc.gov

Performance Indicator:
Mitigating System Performance Index (Emergency AC Power Systems) (MS06)
Mitigating System Performance Index (High Pressure Injection Systems) (MS07)
Mitigating System Performance Index (Heat Removal Systems) (MS08)
Mitigating System Performance Index (Residual Heat Removal Systems) (MS09)
Mitigating System Performance Index (Cooling Water Systems) (MS10)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: 18 months after approval or completion of a licensee's next periodic update of their PRA model and associated basis document update following approval, whichever is later

Question Section

Question #1 –What are the on-going PRA Technical Adequacy requirements for MSPI implementation?

NEI 99-02, Rev. 7 Guidance needing interpretation (include page and line citation):

Page 34, line 7-13
Specific requirements appropriate for this PRA application are defined in Appendix G. Any questions related to the interpretation of these requirements, the use of alternate methods to meet the requirements or the conformance of a plant-specific PRA to these requirements will be arbitrated by an Industry/NRC expert panel. If the panel determines that a plant-specific PRA does not meet the requirements of Appendix G such that the MSPI would be adversely affected, an appropriate remedy will be determined by the licensee and approved by the panel. The decisions of this panel will be binding.

Page G-4 through G-6
G 2. PRA Requirements

G 2.1 Discussions

The MSPI application can be considered a Phase 2 application under the NRC's phased approach to PRA quality. The MSPI is an index that is based on internal initiating events, full-power PRA, for which the ASME Standard has been written. The Standard has been endorsed by the staff in RG 1.200, which has been issued for trial use.

Licensees should assure that their PRA is of sufficient technical adequacy to support the MSPI application by one of the following alternatives:

G 2.1.1 Alternative A (Consistent with MSPI PRA Task Group recommendations)

a) Resolve the peer review Facts and Observations (F&Os) for the plant PRA that are classified as being in category A or B, or document the basis for a determination that any open A or B F&Os will not significantly impact the MSPI calculation. Open A or B F&Os are significant if collectively their resolution impacts any Birnbaum values used in MSPI by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify the impact. If an open A or B F&O cannot be resolved by April 1, 2006 and significantly impacts the MSPI calculation, a modified Birnbaum value equal to a factor of 3 times the median Birnbaum value from the associated cross comparison group for pumps/diesels and 3 times the plant values for valves/breakers should be used in the MSPI calculation at the index, system or component level, as appropriate, until the F&O is resolved.

And

b) Perform a self assessment using the NEI-00-02 process as modified by Appendix B of RG 1.200 for the ASME PRA Standard supporting level requirements identified by the MSPI PRA task group and resolve any identified issues or document the basis for a determination that any open issues will not significantly impact the MSPI calculation. Identified issues are considered significant if they impact any Birnbaum values used in MSPI by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify the impact. If an identified issue cannot be resolved by April 1, 2006 and significantly impacts the MSPI calculation, a modified Birnbaum value equal to a factor of 3 times the median Birnbaum value from the associated cross comparison group for pumps/diesels and 3 times the plant value for valves/breakers should be used in the MSPI calculation at the index, system or component level, as appropriate, until the issue is resolved.

G 2.1.2 Alternative B (Consistent with RG 1.174 guidance)

a) Resolve the peer review Facts and Observations (F&Os) for the plant PRA that are classified as being in category A or B, or document the basis for a determination that any open A or B F&Os will not significantly impact the MSPI calculation. Open A or B F&Os are significant if collectively their resolution impacts any Birnbaum values used in MSPI by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify the impact. If an open A or B F&O cannot be resolved by April 1, 2006 and significantly impacts the MSPI calculation, a modified Birnbaum value equal to a factor of 3 times the median Birnbaum value from the associated cross comparison group for pumps/diesels and 3 times the plant values for valves/breakers should be used in the MSPI calculation at the index, system or component level, as appropriate, until the F&O is resolved.

And

b) Disposition any candidate outlier issues identified by the industry PRA cross comparison activity. The disposition of candidate outlier issues can be accomplished by:

- Correcting or updating the PRA model;
- Demonstrating that outlier identification was due to valid design or PRA modeling methods; or
- Using a modified Birnbaum value equal to a factor of 3 times the median value from the associated cross comparison group for pumps/diesels and 3 times the plant value for valves/breakers until the PRA model is corrected or updated.

G 2.2 PRA MSPI Documentation Requirements

A. Licensees should provide a summary of their PRA models to include the following:

1. Approved version and date used to develop MSPI data
2. Plant base CDF for MSPI
3. Truncation level used to develop MSPI data

B. Licensees should document the technical adequacy of their PRA models, including:

A. Justification for any open category A or B F&Os that will not be resolved prior to April 1, 2006.
B. Justification for any open issues from:
a. The self-assessment performed for the supporting requirements (SR) identified in Table 5, taking into consideration Appendix B of RG 1.200 (trial), with particular attention to the notes in Table 4 of the MSPI PRA task group report.

-- OR --

b. Identification of any candidate outliers for the plant from the group cross-comparison studies.

C. Licensees should document in their PRA archival documentation:

1. A description of the resolution of the A and B category F&Os identified by the peer review team.
2. Technical bases for the PRA.

Table G-5

TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment	
1**Supporting Requirement**	**Comments**
IE-A4	Focus on plant-specific initiators and special initiators, especially loss of DC bus, Loss of AC bus, or Loss of room cooling type initiators
IE-A7	Category I in general. However, precursors to losses of cooling water systems in particular, e.g., from fouling of intake structures, may indicate potential failure mechanisms to be taken into account in the system analysis (IE-C6, 7, 8, 9)
IE-A9	Category II for plants that choose fault trees to model support systems. Watch for initiating event frequencies that are substantially (e.g., more than 3 times) below generic values.

TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment	
1Supporting Requirement	Comments
IE-C1	Focus on loss of offsite power (LOOP) frequency as a function of duration
IE-C2	Focus on LOOP and medium and small LOCA frequencies including stuck open PORVs
IE-C6	For plants that choose fault trees for support systems, attention to loss of cooling systems initiators.
IE-C9	Category II for plants that choose fault trees for support systems. Pay attention to initiating event frequencies that are substantially (i.e., more than 3 times) below generic values
AS-A3	Focus on credit for alternate sources, e.g., gas turbines, CRD, fire water, SW cross-tie, recovery of FW
AS-A4	Focus on credit for alternate sources, e.g., gas turbines, CRD, fire water, SW cross-tie, recovery of FW
AS-A5	Focus on credit for alternate sources, e.g., gas turbines, CRD, fire water, SW cross-tie, recovery of FW
AS-A9	Category II for MSPI systems and components and for systems such as CRD, fire water, SW cross-tie, recovery of FW
AS-A10	Category II in particular for alternate systems where the operator actions may be significantly different, e.g., more complex, more time limited.
AS-B3	Focus on credit for injection post-venting (NPSH issues, environmental survivability, etc.)
AS-B6	Focus on (a) time phasing in LOOP/SBO sequences, including battery depletion, and (c) adequacy of CRD as an adequate injection source.
SC-A4	Focus on modeling of shared systems and cross-ties in multi-unit sites
SC-B1	Focus on proper application of the computer codes for T/H calculations, especially for LOCA, IORV, SORV, and F&B scenarios.
SC-C1	Category II
SY-A4	Category II for MSPI systems and components
SY-A11	Focus on (d) modeling of shared systems

TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment	
1Supporting Requirement	Comments
SY-A20	Focus on credit for alternate injection systems, alternate seal cooling
SY-B1	Should include EDG, AFW, HPI, RHR CCFs
SY-B5	Focus on dependencies of support systems (especially cooling water systems) to the initiating events
SY-B9	Focus on credit for injection post-venting (NPSH issues, environmental survivability, etc.)
SY-B15	Focus on credit for injection post-venting (NPSH issues, environmental survivability, etc.)
HR-E1	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-E2	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-G1	Category II , though Category I for the critical HEPs would produce a more sensitive MSPI (i.e., fewer failures to change a color)
HR-G2	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-G3	Category I. See note on HR-G1. Attention to credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-G5	Category II. See note on HR-G1.
HR-H2	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-H3	The use of some systems may be treated as a recovery action in a PRA, even though the system may be addressed in the same procedure as a human action modeled in the accident sequence model (e.g., recovery of feedwater may be addressed in the same procedure as feed and bleed). Neglecting the cognitive dependency can significantly decrease the significance of the sequence.
DA-B1	Focus on service condition (clean vs. untreated water) for SW systems

TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment	
1Supporting Requirement	Comments
DA-C1	Focus on LOOP recovery
DA-C15	Focus on recovery from LOSP and loss of SW events
DA-D1	For BWRs with isolation condenser, focus on the likelihood of a stuck open SRV
QU-B2	Truncation limits should be chosen to be appropriate for F-V calculations.
QU-B3	This is an MSPI implementation concern and should be addressed in the guidance document. Truncation limits should be chosen to be appropriate for F-V calculations.
QU-D3	Understanding the differences between plant models, particularly as they affect the MSPI, is important for the proposed approach to the identification of outliers recommended by the task group.
QU-D5	Category II for those who have used fault tree models to address support system initiators.
QU-E4	Category II for the issues that directly affect the MSPI

Event or circumstances requiring guidance interpretation:

Introduction/Background

NEI 99-02 (Reference 1), Appendix G contains guidance regarding methods by which the licensee can establish the technical adequacy of their probabilistic risk assessment (PRA) to support the Mitigating System Performance Index (MSPI). This guidance has not been updated to reflect the latest approved versions of the ASME/ANS PRA Standard (Reference 2). In addition, questions have recently arisen regarding the need for guidance on the maintenance and update of PRA models used to support MSPI. This paper explores some of the issues raised and provides recommended approaches for resolving each issue. A proposed revision of NEI 99-02 Appendix G incorporating the proposed changes is included as an attachment.

Summary of Issues

In addition to general update of NEI 99-02 Appendix G to reflect current references, several technical issues have been raised concerning PRA technical adequacy for MSPI. These issues may be grouped into the following categories:

- Characteristics and Attributes for the PRA Maintenance and Upgrade Process Applicable to MSPI
  - Should thresholds for a PRA model update based on impact on the MSPI resulting from pending model changes be established?
  - Should a recommended frequency and scope for PRA data updates be established?

  - Should guidance be provided concerning the frequency and scope of PRA model updates (e.g., incorporation of credit for alternate portable equipment, incorporation of consensus methods)?
- Treatment of Outstanding Peer Review Findings
  - Is the current guidance requiring use of a modified Birnbaum value equal to a factor of three times the median Birnbaum value from the associated cross comparison group for pumps/diesels and three times the plant values for valves/breakers technically sound?
  - What constitutes adequate resolution of a Peer Review Finding
- Assessment of PRA Model Maintenance and Upgrade
  - Is a peer review of upgraded methodologies required prior to use of PRA results in MSPI?

Each of these issues is discussed in detail in the remainder of this FAQ.

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

<u>The Licensee's Position:</u>

Characteristics and Attributes for the PRA Configuration Control Program Applicable to MSPI

The characteristics and attributes of a PRA Configuration Control program are described in ASME/ANS Standard Section 1-5 (Reference 2). The industry peer review process described in NEI 00-02 (Reference 3) includes a Maintenance and Update (MU) checklist that can be used as a guide to indicate specific items that should be considered with respect to the PRA Configuration Control program. NEI05-04 (Reference 4) references use of this checklist as a means to determine that a utility PRA Configuration Control program satisfies the requirements of ASME/ANS PRA Standard Section 1-5. It is expected that a PRA Configuration Control program that has been peer reviewed and found to be consistent with the guidance of the ASME/ANS PRA Standard Section 1-5 will generally maintain the technical adequacy of the PRA model to a sufficient level to support MSPI. However, there are some clarifications that may be needed with respect to MSPI.

ASME/ANS PRA Standard paragraph 1-5.2(b) states that the PRA Configuration Control program shall include "a process that maintains and upgrades the PRA to be consistent with the as-built, as operated plant." ASME/ANS PRA Standard paragraph 1-5.2(c) states that the PRA Configuration Control program shall include "a process that ensures that the cumulative impact of pending changes is considered when applying the PRA." Taken together, it is recommended that the PRA Configuration Control program consider the cumulative impact of pending changes on the indicators for MSPI monitored systems to determine whether a PRA model update is needed. Pending model changes related to plant design changes, credit for alternate portable equipment, peer review findings, and other changes to the PRA model to correct identified issues are expected to be tracked as pending changes. This will ensure that the PRA model is maintained sufficiently consistent with the as-built, as-operated plant for the MSPI application.

Analysis of data trends documented in NUREG/CR-5750 (Reference 5), NUREG/CR-6928 (Reference 6), and NUREG/CR-6890 (Reference 7) indicate that there are no statistically significant trends in either initiating event frequency or generic component reliability data over periods of five to ten years. Therefore, update of this data on a frequency of at least once per 10

years is considered adequate for PRA models supporting MSPI. The recommendations of the MSPI PRA Quality Task Group (Reference 8) noted that the MSPI pilot program did not find that parameter values were a significant source of concern for MSPI sensitivity. However, the data maintenance process shall be consistent with the above guidance for the PRA Configuration Control program and supporting requirements in the ASME/ANS PRA Standard Initiating Event Analysis (IE), Data Analysis (DA), and Human Reliability Analysis (HR) technical elements.

The recommendations of the MSPI PRA Quality Task Group (Reference 8) also include the Task Group's assessment of the ASME standard capability categories required to support the MSPI application. NEI 99-02 Table G 5 incorporated part of this assessment by detailing those supporting requirements requiring additional self-assessment to address differences between the criteria used to review the PRA using the NEI-00-02 process to support MSPI implementation. Table 3-1 in Reference 8 included the recommended capability category for each supporting requirement considered applicable to MSPI based on ASME PRA Standard RA-Sa-2003. To clarify the applicable supporting requirements and the required capability category for each applicable supporting requirement, Table G 5 should be updated to include the current ASME/ANS PRA Standard supporting requirements corresponding to Reference 8 Table 3-1 with applicable capability categories and clarifying notes. The revised Table G 5 will then provide a basis for determination of which peer review F&Os need to be assessed for impact on MSPI. Prior to updating Table G.5 of NEI 99-02, the previous conclusions of the MSPI PRA Quality Task Group should be reviewed to determine if the conclusions are applicable to the current post-implementation status of MSPI.

The industry has established practices to ensure that the PRA is sufficient to be used for regulatory decisions. The configuration control program supporting the MSPI program should meet the following requirements:

- Use of personnel qualified for the analysis.
- Use of procedures that ensure control of documentation, including revisions, and provide for technical review, verification, or checking of calculations and information used in the analyses.
- Provision for documentation and maintenance of records.
- Use of procedures that ensure that appropriate actions are taken in accordance with established plant practices if assumptions, analyses, or information used in previous decision-making are changed (e.g., licensee voluntary action) or determined to be in error.

The following clarifications are applicable.

a. Pending model changes to be considered for MSPI are those related to implemented plant design and operational changes, identified errors in the PRA model, and F&Os characterized as findings related to those supporting requirements identified in Table G 5. NEI 05-04 defines a finding as an observation (an issue or discrepancy) that is necessary to address to ensure: 1) the technical adequacy of the PRA (relative to a Capability Category), 2) the capability/robustness of the PRA update process, or 3) the process for evaluating the necessary capability of the PRA technical elements (to support applications). Note that F&Os characterized as findings related to model changes required to meet Capability Category II are not considered pending model changes for MSPI if Table G 5 indicates that Capability Category I is sufficient.
b. The evaluation process for pending PRA model changes should include consideration of the impact on MSPI inputs in determining the need for a PRA model update.

c. The PRA supporting the MSPI program should be developed and reviewed by qualified personnel.
d. The PRA model and any supplemental analyses supporting the MSPI program should be subject to a technical review covering both the inputs and results of the analyses prior to their use.

Treatment of Open Peer Review Findings

The current guidance in NEI 99-02 states the following with respect to the treatment of peer review findings:

> Resolve the peer review Facts and Observations (F&Os) for the plant PRA that are classified as being in category A or B, or document the basis for a determination that any open A or B F&Os will not significantly impact the MSPI calculation. Open A or B F&Os are significant if collectively their resolution impacts any Birnbaum values used in MSPI by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify the impact. If an open A or B F&O cannot be resolved by April 1, 2006 and significantly impacts the MSPI calculation, a modified Birnbaum value equal to a factor of 3 times the median Birnbaum value from the associated cross comparison group for pumps/diesels and 3 times the plant values for valves/breakers should be used in the MSPI calculation at the index, system or component level, as appropriate, until the F&O is resolved.

This guidance was developed to support initial implementation of MSPI and has several problems with respect to the current implementation status of MSPI.

Reviews of several PRA models indicate that a modified Birnbaum value based on three times the median Birnbaum value reported in WCAP-16464 (Reference 6) may actually be lower than the plant-specific Birnbaum value for one or more pump groups. This indicates that the use of the current guidance may not produce consistent impact for all plants.

The use of modified Birnbaum values based on plant-specific sensitivity results used to determine the impact of open peer review findings or based on two times the plant-specific Birnbaum values for all monitored components affected by the finding will provide a more consistent adjustment. However, this also may not be appropriate for all peer review findings. For example, if the peer review finding is associated with deficiencies in the common cause failure modeling, a restriction on the use of plant-specific CCF adjustment factors lower than the generic values until the issue is resolved may be more appropriate.

Therefore, it is recommended that the fixed adjustment value be eliminated and that any modified Birnbaum values applied for open finding level F&Os (equivalent to NEI 00-02 categories A and B) be based on plant-specific evaluation of the potential impact of model changes required to address the finding.

To ensure that Peer Review findings are appropriately incorporated in a model revision, a review of the actions taken to address the finding should be provided by a technically qualified individual. If the review determines that the finding was appropriately addressed, that finding can be considered closed with respect to MSPI.

Assessment of PRA Model Maintenance and Upgrades

The ASME/ANS PRA Standard defines a PRA upgrade as "the incorporation into a PRA model of a new methodology or significant changes in scope or capability that impact the significant accident sequences or the significant accident progression sequences." For MSPI, the PRA maintenance and upgrade activities of concern are those that impact the scope of the PRA model used for developing MSPI inputs. This excludes PRA maintenance and upgrades related only to analysis of internal flooding, Level 2/LERF, fire, seismic, and other external events.

For MSPI, inputs from PRA maintenance (e.g., updates of reliability and unavailability data, incorporation of procedure changes in the HRA, etc.) or upgrade may be used as long as an internal technical review has been completed under the utility's PRA Configuration Control program. However, those changes classified as upgrades should be included in the scope of any subsequent peer review scheduled for another reason. Any findings resulting from that subsequent peer review will be addressed as pending model changes and treated consistent with the above guidance for treatment of open peer review findings.

Implementation Guidance

The new PRA Technical Adequacy requirements for MSPI are to be completed within 18 months or completion of a licensee's next periodic update of their PRA model and associated basis document update following approval, whichever is later. The steps to be taken during this implementation phase (with expected task duration) include:

- Comparison of Supporting Requirement (SR) capability categories from most recent peer review to Table G 5 requirements (expected effort one to five days),
- Identification and documentation of findings that have been resolved for those SRs that did not meet the required capability category during the peer review (expected effort three to six months),
- Identification and documentation of findings that have not been resolved for those SRs that did not meet the required capability category during the peer review (expected effort one to three months),
- Assessment and documentation of the aggregate impact of unresolved findings and other pending PRA model changes on the MSPI inputs (expected effort two to four months), and
- Update and issue the MSPI Basis Document (expected effort one to two months).

References

1. NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 7, Nuclear Energy Institute, October 2009.
2. ASME/ANS RA-Sa-2009, Addenda to ASME/ANS RA-S-2008 Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, American Society of Mechanical Engineers, New York, NY, February 2009.
3. NEI 00-02, Probabilistic Risk Assessment (PRA) Peer Review Process Guidance, Revision A3, Nuclear Energy Institute, March 2000.
4. NEI 05-04, Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard, Revision 2, Nuclear Energy Institute, November 2008.
5. NUREG/CR-5750, Rates of Initiating Events at US Commercial Nuclear Power Plants: 1987-1995, U.S. Nuclear Regulatory Commission, February 1999.
6. NUREG/CR-6928, Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants, U.S. Nuclear Regulatory Commission, February 2007.

7. NUREG/CR-6890, Volume 1, Reevaluation of Station Blackout Risk at Nuclear Power Plants Analysis of Loss of Offsite Power Events: 1986-2004, U.S. Nuclear Regulatory Commission, December 2005.
8. Recommendations of the MSPI PRA Quality Task Group, ML043510095, December 16, 2004.
9. WCAP-16464-NP, Westinghouse Owner's Group Mitigating Systems Performance Index Cross Comparison (PA-RMSC-0209), Revision 0, Westinghouse Electric Company LLC, August 2005.

The NRC's Position:

This FAQ captures the changes to NEI 99-02 proposed in the "PRA Technical Adequacy for MSPI" white paper discussed in the ROP Working Group (The last documented version of this white paper is available through Agencywide Document Access and Management System (ADAMS) Accession No. ML13324B139). The poposed changes clarify the guidance in Appendix G of NEI 99-02 on methods by which the licensee can establish the technical adequacy of the PRA supporting MSPI. The staff agrees with the proposed changes and recommends incorporation of these to NEI 99-02.

Potentially relevant existing FAQ numbers:

None

Response Section

Proposed Resolution of FAQ

The following complete replacement of NEI 99-02 Appendix G is proposed:

APPENDIX G

MSPI Basis Document Development

To implement the Mitigating Systems Performance Index (MSPI), Licensees will develop a plant specific basis document that documents the information and assumptions used to calculate the Reactor Oversight Program (ROP) MSPI. This basis document is necessary to support the NRC inspection process, and to record the assumptions and data used in developing the MSPI on each site. A summary of any changes to the basis document are noted in the comment section of the quarterly data submission to the NRC.

The Basis document will have two major sections. The first described below will document the information used in developing the MSPI. The second section will document the conformance of the plant specific PRA to the requirements that are outlined in this appendix.

G 1. MSPI Data

The basis document provides a separate section for each monitored system as defined in Section 2.2 of NEI 99-02. The section for each monitored system contains the following subsections:

G 1.1 System Boundaries

This section contains a description of the boundaries for each train of the monitored system. A plant drawing or figure (training type figure) should be included and marked adequately (i.e., highlighted trains) to show the boundaries. The guidance for determining the boundaries is provided in Appendix F, Section 1.1 of NEI 99-02.

G 1.2 Risk Significant Functions

This section lists the risk significant functions for each train of the monitored system. Risk Significant Functions are defined in section 2.2 of NEI 99-02. Additional detail is given in Appendix F, Section 1.1.1 and Section 5 “Additional Guidance for Specific Systems”. A single list for the system may be used as long as any differences between trains are clearly identified. This section may also be combined with the section on Success Criteria if a combination of information into a table format is desired. If none of the functions for the system are considered risk significant, identify the monitored function as defined in section F 1.1.1

G 1.3 Success Criteria

This section documents the success criteria as defined in Section 2.2 of NEI 99-02 for each of the identified monitored functions for the system. Additional detail is given in Appendix F, Section
2.1.1. **The criteria used are the documented PRA success criteria.**

- If the licensee has chosen to use design basis success criteria in the PRA, then provide a statement in this section that states the PRA uses design basis success criteria.
- If success criteria from the PRA are different from the design basis, then the specific differences from the design basis success criteria shall be documented in this section. Provide the actual values used to characterize success such as: *The time required in the PRA for the EDG to successfully reach rated speed and voltage is 15 seconds.*

Where there are different success criteria for different monitored functions or different success criteria for different initiators within a monitored function, all should be recorded and the most restrictive shown as the one used, with the exception of ATWS related success criteria which are not in the scope of MSPI.

G 1.4 Mission Time

This section documents the risk significant mission time, as defined in Section 2.3.6 of Appendix F, for each of the identified monitored functions identified for the system. The following specific information should be included in support of the EDG mission time if a value less than 24 hours is used:

- EDG Mission Time with highest Birnbaum
- Basic Event and Description (basis for Birnbaum)
- Other Emergency Power Failure to Run Basic Events, Descriptions, mission time and Birnbaums (those not selected)
- Method for reduced mission time (e.g., Convolution, Multiple Discrete LOOP (Loss of Offsite Power) Initiating Events, Other)
- Loss of Offsite Power (LOOP) Initiating Events, Description and Frequency
- Basis for LOOP Frequency (Industry/NRC Reference)
- Basis for LOOP Non-recovery Failure (Industry/NRC Reference)
- Credit for Emergency Power Repair (Yes/No)
- If repair credited, failure probability of repair and basis

G 1.5 Monitored Components

This section documents the selection of monitored components as defined in Appendix F, Section 2.1.2 of NEI 99-02 in each train of the monitored system. A listing of all monitored pumps, breakers and emergency power generators should be included in this section. A listing of AOVs, HOVs, SOVs and MOVs that change state to achieve the monitored functions should be provided as potential monitored components. The basis for excluding valves and breakers in this list from monitoring should be provided. Component boundaries as described in Appendix F,

Section 2.1.3 of NEI 99-02 should be included where appropriate.

G 1.6 Basis for Demands/Run Hours (estimate or actual)

The determination of reliability largely relies on the values of demands, run hours and failures of components to develop a failure rate. This section documents how the licensee will determine the demands on a component. Several methods may be used.

- Actual counting of demands/run hours during the reporting period
- An estimate of demands/run hours based on the number of times a procedure or other activities are performed plus either actual ESF demands/run hours or "zero" ESF demands/run hours
- An estimate based on historical data over a year or more averaged for a quarterly average plus either actual ESF demands/run hours or "zero" ESF demands/run hours

The method used, either actual or estimated values, shall be stated. If estimates are used for test or operational demands or run hours then the process used for developing the estimates shall be described and estimated values documented. If the estimates are based on performance of procedures, list the procedures and the frequencies of performance that were used to develop the estimates.

G 1.7 Short Duration Unavailability

This section provides a list of any periodic surveillances or evolutions of less than 15 minutes of unavailability that the licensee does not include in train unavailability. The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact.

G 1.8 PRA Information used in the MSPI

G 1.8.1 Unavailability FV and UA

This section includes a table or spreadsheet that lists the basic events for unavailability for each train of the monitored systems. This listing should include the probability, FV, and FV/probability ratio and text description of the basic event or component ID. An example format is provided as Table 1 at the end of this appendix. If the event chosen to represent the train is not the event that results in the largest ratio, provide information that describes the basis for the choice of the specific event that was used.

G 1.8.1.1 Unavailability Baseline Data

This section includes the baseline unavailability data by train for each monitored system. The discussion should include the basis for the baseline values used. The detailed basis for the baseline data may be included in an appendix to the MSPI Basis Document if desired.

The basis document should include the specific values for the planned and unplanned unavailability baseline values that are used for each train or segment in the system.

G 1.8.1.2 Treatment of Support System Initiator(s)

This section documents whether the cooling water systems are an initiator or not. This section provides a description of how the plant will include the support system initiator(s) as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section. A sample table format for presenting the results of a plant specific calculation for those plants that do not explicitly model the effect on the initiating event contribution to risk is shown in Table 4 at the end of this appendix.

G 1.8.2 Unreliability FV and UR

There are two options described in Appendix F for the selection of FV and UR values, the selected option should be identified in this section. This section also includes a table or spreadsheet that lists the PRA information for each monitored component. This listing should include the Component ID, event probability, FV, the common cause adjustment factor and FV/probability ratio and text description of the basic event or component ID. An example format is provided as Table 2 at the end of this appendix. If individual failure mode ratios (vice the maximum ratio) will be used in the calculation of MSPI, then each failure mode for each component will be listed in the table.

A separate table should be provided in an appendix to the basis document that provides the complete set of basic events for each component. An example of this for one component is shown in Table 3 at the end of this appendix. Only the basic event chosen for the MSPI calculation requires completion of all table entries.

G 1.8.2.1 Treatment of Support System Initiator(s)

This section documents whether the cooling water systems are an initiator or not. This section provides a description of how the plant will include the support system initiator(s) as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section. A sample table format for presenting the results of a plant specific calculation for those plants that do not explicitly model the effect on the initiating event contribution to risk is shown in Table 4 at the end of this appendix.

G 1.8.2.2 Calculation of Common Cause Factor

This section contains the description of how the plant will determine the common cause factor as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The

results should also be included in this section.

G 1.9 Assumptions

This section documents any specific assumptions made in determination of the MSPI information that may need to be documented. Causes for documentation in this section could be special methods of counting hours or runtimes based on plant specific designs or processes, or other instances not clearly covered by the guidance in NEI 99-02.

G 2. PRA Requirements

G 2.1 Discussion

The MSPI application can be considered a Phase 2 application under the NRC's phased approach to PRA quality. A Phase 2 application refers to an application where the baseline PRA that supports the application meets the applicable consensus PRA standards. The MSPI is an index that is based on internal initiating events, full-power PRA, for which the ASME/ANS PRA Standard has been written.

Licensees should assure that their PRA is of sufficient technical adequacy to support the MSPI application as follows:

G 2.1.1 PRA Model Scope and Level of Detail

The PRA supporting the MSPI program should meet the following requirements:

a) The scope of the PRA to be used for MSPI is a Level 1 internal events model covering full power operation. Level 2/LERF, internal floods and fires are excluded from the internal events scope for MSPI.
b) The PRA should be of sufficient detail to support the development of plant-specific Birnbaum importance measures for the components and trains/segments within the scope of MSPI.
c) The PRA should be of sufficient detail to ensure the impacts of designed-in dependencies (e.g., support system dependencies, functional dependencies, and dependencies on operator actions) are correctly captured.

G 2.1.2 Characteristics and Attributes of the PRA Configuration Control Program

The characteristics and attributes of a PRA Configuration Control program are described in

ASME/ANS Standard Section 1-5. The configuration control program supporting the MSPI program should meet the following requirements:

a) a process for monitoring PRA inputs and collecting new information
b) a process that maintains and upgrades the PRA to be consistent with the as-built, as operated plant
c) a process that ensures that the cumulative impact of pending changes is considered when applying the PRA
d) a process that maintains configuration control of computer codes used to support PRA quantification
e) documentation of the PRA Maintenance and Upgrade process

The following clarifications are applicable.

a) Pending model changes to be considered for MSPI are those related to implemented plant design and operational changes, identified errors in the PRA model, and F&Os characterized as findings related to those supporting requirements identified in Table G 5. NEI 05-04 defines a finding as an observation (an issue or discrepancy) that is necessary to address to ensure: 1) the technical adequacy of the PRA (relative to a Capability Category), 2) the capability/robustness of the PRA update process, or 3) the process for evaluating the necessary capability of the PRA technical elements (to support applications). Note that F&Os characterized as findings related to model changes required to meet Capability Category II are not considered pending model changes for MSPI if Table G 5 indicates that Capability Category I is sufficient.
b) The evaluation process for pending PRA model changes should include consideration of the impact on MSPI inputs in determining the need for a PRA model update.
c) The PRA supporting the MSPI program should be developed and reviewed by qualified personnel.
d) The PRA model and any supplemental analyses supporting the MSPI program should be subject to a technical review covering both the inputs and results of the analyses prior to their use.

G 2.1.3 Treatment of Pending Model Changes

To ensure that Peer Review findings are appropriately incorporated in a model revision, a review of the actions taken to address the finding should be provided by a technically qualified individual. If the review determines that the finding was appropriately addressed, that finding can be considered resolved with respect to MSPI.

Pending model changes that cannot be incorporated into a revision to the site PRA of record prior to the next reporting quarter should be assessed consistent with the PRA Configuration Control program.

If an evaluation of the cumulative impact of proposed resolutions for the pending model changes

results in greater than or equal to a predicted factor of three change in the corrected Birnbaum value of an MSPI monitored train or component, the MSPI basis document should be updated to include revised CDE inputs the quarter following identification of the increased impact. The use of supplemental analysis to estimate the revised MSPI inputs is allowed until the site PRA of record is revised. This may be the analysis used to determine the need for the change or a more refined model.

If an evaluation of the cumulative impact of proposed resolutions for the pending model changes results in less than a predicted factor of three change in the corrected Birnbaum value of an MSPI monitored train or component, the evaluation should be documented to demonstrate that the pending change(s) have no significant impact on the MSPI results (i.e., there is no change in the calculated indicator colors),

If the an evaluation of pending changes indicate that the Birnbaum value for a component previously excluded from monitoring will be greater than 1.0E-06, the MSPI basis document should be updated to reflect the new Birnbaum values the quarter following identification of the increased impact. The use of supplemental analysis to estimate the revised MSPI inputs is allowed until the site PRA of record is revised. This may be the analysis used to determine the need for the change or a more refined model.

G 2.1.4 Assessment of PRA Model Maintenance and Upgrades

The ASME/ANS PRA Standard defines a PRA upgrade as "the incorporation into a PRA model of a new methodology or significant changes in scope or capability that impact the significant accident sequences or the significant accident progression sequences." For MSPI, the PRA maintenance and upgrade activities of concern are those that impact the scope of the PRA model used for developing MSPI inputs. This excludes PRA maintenance and upgrades related only to analysis of internal flooding, Level 2/LERF, fire, seismic, and other external events.

The differentiation between PRA maintenance and upgrades is further discussed in Non-mandatory Appendix 1-A, *PRA Maintenance, PRA Upgrade, and the Advisability of Peer Review.* For MSPI, inputs from PRA maintenance (e.g., updates of reliability and unavailability data, incorporation of procedure changes in the HRA, etc.) or upgrade may be used as long as an internal technical review has been completed under the utility's PRA Configuration Control program. However, those changes classified as upgrades should be included in the scope of any subsequent peer review scheduled for another reason. Any findings resulting from that subsequent peer review will be identified as pending PRA model changes as described in Section G 2.1.2 and evaluated as described in Section G 2.1.3.

G 2.2 PRA MSPI Documentation Requirements

A. Licensees should provide a summary of their PRA models to include the following:

1. Approved version and date of the site PRA of record used to develop MSPI data
2. Plant base CDF for MSPI
3. Truncation level used to develop MSPI data

B. Licensees should document the technical adequacy of their PRA models, including:

1. Description of the PRA Configuration Control program and identification of applicable procedures.
2. Description of the process used to qualify personnel involved in the preparation and technical review of the PRA analyses supporting MSPI.
3. Justification for any open finding level F&Os associated with those SRs identified in Table G5 that are determined to have no impact on the use of the PRA model for MSPI.
4. The basis of the adjusted Birnbaum values applied to reflect pending model changes (e.g., supplemental analysis or penalty factor).

C. Licensees should document in their PRA archival documentation:

1. A description of the resolution of the finding level F&Os identified by the peer review team.
2. Results of supplemental analysis used to assess the impact of pending PRA model changes on MSPI monitored trains or components.
3. Documentation of internal technical reviews of PRA model updates and/or supplemental analyses performed to support the MSPI program.
4. Technical bases for the PRA.

G 3. TABLES

Table G 1 Unavailability Data HPSI (one table per system)

Train	Basic Event Name	Basic Event Description	Basic Event Probability (UAP)	Basic Event FVUAP [1]	FVUAP/UAP
A	1SIAP02----MP6CM	HPSI Pump A Unavailable Due to Mntc	3.20E-03	3.19E-03	9.97E-01
B	1SIBP02----MP6CM	HPSI Pump B Unavailable Due to Mntc	3.20E-03	3.85E-03	1.20E+00

1. Adjusted for IEF correction if used

Table G 2 – AFW System Monitored Component PRA Information

Component	Basic Event	Description	Basic Event Probability (URPC)	Basic Event FVURC	[FV/UR]*ind*	CC Adjustment Factor (A)	CC Adjustment Used	Adjusted Birnbaum
1MAFAP01	1AFASYS----AFACM	Train A Auxiliary Feedwater Pump Fails to Start	2.75E-03	2.33E-02	8.49E+00	1	Generic	1.1E-04
1MAFBP01	1AFBP01----MPAFS	Train B Auxiliary Feedwater Pump Fails to Start	6.73E-04	4.44E-02	6.59E+01	1.25	Generic	1.1E-03
1MAFNP01	1AFNSYS----AFNCM	Train N Auxiliary Feedwater Pump Fails to Start	1.05E-03	1.10E-02	1.05E+01	1.25	Generic	1.7E-04
1JCTAHV0001	1CTAHV001--MV-FO	CST to AFW Pump N Supply Valve HV1 Fails to Open (Local Fault)	3.17E-03	2.48E-02	7.83E+00	2	Generic	2.0E-04
1JCTAHV0004	1CTAHV004--MV-FO	CST to AFW Pump N Supply Valve HV4 Fails to Open (Local Fault)	3.17E-03	2.48E-02	7.83E+00	2	Generic	2.0E-04

Table G 3 - Unreliability Data (one table per monitored component)

Component Name and ID: HPSI Pump B - 1SIBP02

Basic Event Name	Basic Event Description	Basic Event Probability (URPC)	Basic Event FVURC [1]	[FV/UR]*ind*	Common Cause Adjustment Factor (CCF)	Common Cause Adjustment Generic or Plant Specific	Adjusted Birnbaum
1SIBP02---XCYXOR	HPSI Pump B Fails to Start Due to Override Contact Failure	6.81E-04	7.71E-04	1.13E+00	3.0	Generic	5.0E-05
1SIBP02----MPAFS	HPSI Pump B Fails to Start (Local Fault)	6.73E-04	7.62E-04	1.13E+00			
1SIBP02----MP-FR	HPSI Pump B Fails to Run	4.80E-04	5.33E-04	1.11E+00			
1SABHP-K125RXAFT	HPSI Pump B Fails to Start Due to K125 Failure	3.27E-04	3.56E-04	1.09E+00			
1SIBP02----CB0CM	HPSI Pump B Circuit Breaker (PBB-S04E) Unavailable Due to Mntc	2.20E-04	2.32E-04	1.05E+00			
1SIBP02----CBBFT	HPSI Pump B Circuit Breaker (PBB-S04E) Fails to Close (Local Fault)	2.04E-04	2.14E-04	1.05E+00			

1. Adjusted for IEF correction if used

1 **Table G 4 Cooling Water Support System FV Calculation Results (one table per train/component/failure mode)**

FV*a (or FVc)*	FV*ie*	FV*sa (orFVsc)*	UA (or UR)	Calculated FV (per appendix F) *(result is put in Basic Event column of table 1 or table 2 as appropriate)*

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
IE-A1	MET	
IE-A2	MET	
IE-A3	MET	
IE-A4	I/II	
IE-A5	I	
IE-A6	I	
IE-A7	MET	
IE-A8	I	
IE-A9	I	
IE-A10	MET	
IE-B1	MET	
IE-B2	MET	
IE-B3	I	The difference between CC I and CC II is the emphasis on significant accident sequences. As MSPI focuses on overall CDF and does not consider LERF, the differentiation of accident sequences has minimum impact to MSPI.. Therefore, CC I is appropriate for MSPI. The net impact of combining separate initiating events into a bounding composite event would be to increase the significance of the combined accident sequence. This ensures that any impact on "significant accident sequences" is in the conservative direction, which would tend to increase the importance of the mitigation systems of interest to MSPI.
IE-B4	MET	
IE-B5	MET	
IE-C1	MET	
IE-C2	MET	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
IE-C3	N/A	Not crediting recovery actions is conservative with respect to MSPI. If recovery actions are credited, then IE-C3 must be MET.
IE-C4	Met	
IE-C5	I/II	
IE-C6	MET	
IE-C7	I/II	
IE-C8	MET	
IE-C9	MET	
IE-C10	MET	
IE-C11	MET	
IE-C12	MET	For plants that choose fault trees for support systems, pay attention to initiating event frequencies that are substantially (i.e., more than 3 times) below generic values
IE-C13	1/II	
IE-C14	N/A	Should not impact the Birnbaum importance measure for MSPI monitored components/trains/segments.
IE-C15	N/A	Characterization of uncertainty is only required in this SR to calculate mean values of initiating event frequencies. For the level of accuracy required for MSPI, the use of point estimate values as opposed to mean values for initiating event frequencies is unlikely to make a significant difference.
IE-D1	N/A[3]	
IE-D2	N/A[3]	
IE-D3	N/A	Documentation of uncertainty is not germane to MSPI.
AS-A1	MET	Item b is not required to be met for MSPI.
AS-A2	MET	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
AS-A3	MET	
AS-A4	MET	
AS-A5	MET	
AS-A6	MET	
AS-A7	I/II	
AS-A8	MET	
AS-A9	I	CC I, provided that the generic thermal-hydraulic analysis is conservative.
AS-A10	I	Meeting CC I provides a bounding approach that should result in conservative results for MSPI.
AS-A11	MET	
AS-B1	MET	
AS-B2	MET	
AS-B3	MET	
AS-B4	MET	
AS-B5	MET	
AS-B6	MET	
AS-B7	MET	
AS-C1	N/A[3]	
AS-C2	N/A[3]	
AS-C3	N/A	Documentation of uncertainty is not germane to MSPI.
SC-A1	MET	
SC-A2	I	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
SC-A3	MET	
SC-A4	MET	
SC-A5	I	
SC-A6	MET	
SC-B1	I	
SC-B2	I	
SC-B3	MET	
SC-B4	MET	
SC-B5	MET	
SC-C1	N/A[3]	
SC-C2	N/A[3]	
SC-C3	N/A	Documentation of uncertainty is not germane to MSPI.
SY-A1	MET	
SY-A2	MET	
SY-A3	MET	
SY-A4	I	
SY-A5	MET	
SY-A6	MET	
SY-A7	I/II	
SY-A8	MET	For MSPI, SY-A8 is limited to the modeling of shared components.
SY-A9	MET	
SY-A10	MET	
SY-A11	MET	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
SY-A12	MET	
SY-A13	MET	
SY-A14	MET	
SY-A15	MET	
SY-A16	I/II	
SY-A17	MET	
SY-A18	MET	
SY-A19	MET	
SY-A20	MET	
SY-A21	MET	
SY-A22	I	
SY-A23	MET	
SY-A24	MET	
SY-B1	I	
SY-B2	I/II	
SY-B3	MET	
SY-B4	MET	
SY-B5	MET	
SY-B6	MET	
SY-B7	I	
SY-B8	MET	
SY-B9	MET	
SY-B10	I	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
SY-B11	MET	
SY-B12	MET	
SY-B13	MET	
SY-B14	MET	
SY-B15	MET	
SY-C1	N/A[3]	
SY-C2	N/A[3]	
SY-C3	N/A	Documentation of uncertainty is not germane to MSPI.
HR-A1	MET	
HR-A2	MET	
HR-A3	MET	
HR-B1	I	For the level of accuracy required for MSPI, contributions from failures to restore following maintenance or test are unlikely to make a significant difference.
HR-B2	MET	
HR-C1	MET	
HR-C2	I	For the level of accuracy required for MSPI, contributions from failures to restore following maintenance or test are unlikely to make a significant difference.
HR-C3	MET	
HR-D1	MET	
HR-D2	I	For the level of accuracy required for MSPI, the use of screening values for pre-initiator HEPs is unlikely to make a significant difference.

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
HR-D3	I	For the level of accuracy required for MSPI, the use of screening values for pre-initiator HEPs is unlikely to make a significant difference.
HR-D4	MET	
HR-D5	MET	
HR-D6	N/A	For the level of accuracy required for MSPI, the use of mean values for pre-initiator HEPs is unlikely to make a significant difference.
HR-D7	I/II	
HR-E1	MET	
HR-E2	MET	
HR-E3	II/III	For MSPI purposes a detailed talk through with operations OR training personnel is sufficient.
HR-E4	II/III	
HR-F1	I/II	
HR-F2	II	Meeting CC II ensures that the complexity of the task is fully understood.
HR-G1	I	Meeting CC I for the critical HEPs would produce a more sensitive MSPI (i.e., fewer failures to change a color).
HR-G2	MET	
HR-G3	I	Meeting CC I requires some measure of scenario-induced stress. The additional PSFs listed in CC II/III should not have a significant impact on the final HEP. Therefore, meeting CC I is sufficient for MSPI.
HR-G4	I	
HR-G5	II	
HR-G6	MET	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
HR-G7	MET	
HR-G8	N/A	For the level of accuracy required for MSPI, the use of mean values for post-initiator HEPs is unlikely to make a significant difference.
HR-H1	N/A	Not crediting recovery actions is conservative with respect to MSPI.
HR-H2	N/A	Not crediting recovery actions is conservative with respect to MSPI. If recovery actions are credited, then HR-H2 must be MET.
HR-H3	MET	If recovery actions are credited, then HR-H3 must be met.
HR-I1	N/A[3]	
HR-I2	N/A[3]	
HR-I3	N/A	Documentation of uncertainty is not germane to MSPI.
DA-A1	MET	
DA-A2	MET	
DA-A3	MET	
DA-A4	MET	
DA-B1	I	
DA-B2	I/II	
DA-C1	MET	
DA-C2	MET	Required only for MSPI components.
DA-C3	MET	Required only if plant-specific data is used.
DA-C4	MET	Required only if plant-specific data is used.
DA-C5	MET	Required only if plant-specific data is used.
DA-C6	MET	Required only if plant-specific data is used.

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
DA-C7	I	
DA-C8	I	
DA-C9	I/II	
DA-C10	I	
DA-C11	MET	
DA-C12	MET	
DA-C13	I	
DA-C14	MET	
DA-C15	MET	
DA-C16	MET	
DA-D1	II	Required only for MSPI components. Non-MSPI components need to meet CC I.
DA-D2	MET	
DA-D3	N/A	The characterization of uncertainty does not play a role in MSPI.
DA-D4	I, II/III	If a Bayesian approach is used, its validity should be examined at CC II/III.
DA-D5	I	
DA-D6	I	
DA-D7	MET	
DA-D8	I	
DA-E1	N/A[3]	
DA-E2	N/A[3]	
DA-E3	N/A	Documentation of uncertainty is not germane to MSPI.

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
QU-A1	MET	
QU-A2	MET	
QU-A3	I	It is judged that performing a point estimate calculation, rather than using a formal propagation of uncertainty, will not have significant impact on the accident sequences and cutsets involving the MSPI systems.
QU-A4	MET	
QU-A5	N/A	Not crediting recovery actions is conservative with respect to MSPI.
QU-B1	MET	
QU-B2	N/A	Truncation requirements specific to MSPI are established in NEI 99-02 Section F 1.3.1.
QU-B3	N/A	Truncation requirements specific to MSPI are established in NEI 99-02 Section F 1.3.1.
QU-B4	MET	
QU-B5	MET	
QU-B6	N/A	Accounting for successes is only important for accident sequence determination. As MSPI focuses on overall CDF and does not consider LERF, the accident sequences have no impact to MSPI. Therefore, this SR is not applicable for MSPI.
QU-B7	MET	
QU-B8	MET	
QU-B9	N/A	For MSPI, not setting flags to TRUE is conservative.
QU-B10	MET	
QU-C1	MET	
QU-C2	MET	

TABLE G 5. ASME/ANS PRA Standard Supporting Requirements Requiring Self-Assessment		
Supporting Requirement[1]	**Required Capability Category[2]**	**Comments**
QU-C3	MET	
QU-D1	MET	
QU-D2	MET	
QU-D3	MET	
QU-D4	I	For MSPI, it is not expected that comparison with other plants would yield significant changes to the PRA.
QU-D5	MET	
QU-D6	N/A	Identification of risk insights is not required for MSPI.
QU-D7	MET	
QU-E1	N/A	Uncertainty characterization does not play a role in MSPI.
QU-E2	N/A	Uncertainty characterization does not play a role in MSPI.
QU-E3	N/A	Uncertainty characterization does not play a role in MSPI.
QU-E4	N/A	Uncertainty characterization does not play a role in MSPI.
QU-F1	N/A[3]	
QU-F2	N/A[3]	
QU-F3	N/A[3]	
QU-F4	N/A	Documentation of uncertainty is not germane to MSPI.
QU-F5	N/A[3]	
QU-F6	N/A[3]	

1. LERF and internal flood are outside the scope of MSPI; therefore, all SRs related to LERF and internal flood are N/A and are not included in the table.
2. The Required Capability Category for Supporting Requirements where the action statement spans all three categories is designated as "MET" consistent with the guidance of NEI 05-04, Revision 2, Table 1.
3. Documentation (which includes the PRA model) is expected to sufficiently demonstrate applicable technical supporting requirements (SRs) are met (See Table G5). When the peer review team determines that documentation is inadequate to assess an SR, then the

deficiency (e.g., a peer review finding) should be reflected against the documentation SR and the associated technical SRs. Documentation issues that do not challenge the adequacy of an applicable technical SR are outside the scope of the MSPI technical requirements.

NRC Response

The NRC staff agrees with the proposed changes and recommends incorporation of these to NEI 99-02.

FAQ 13-07 Final Approved

Correctly Scoring Classification Opportunities (DCPP)

Plant: DCPP

Date of Event:

Submittal Date: April 23, 2013

Contact: Brian Ashbrook **Tel/email:** 805.545.6279 bka4@pge.com

NRC Contact: Tel/email:

Performance Indicator: EP01, Drill/Exercise Performance

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: This FAQ is effective immediately for Diablo Canyon. For other licensees, the changes to NEI 99-02 will be effective on April 1, 2014, meaning that licensees will begin applying this FAQ resolution to 2Q2014 data reported to NRC in July 2014.

Question Section

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

Page 44, Lines 19 & 20:

"Timely means:

- classifications are made consistent with the goal of 15 minutes once available parameters reach an Emergency Action Level (EAL)…"

Event or circumstances requiring guidance interpretation:

In a license operator requalification simulator session with a simulated earthquake at T=0, the shift manager (SM) emergency coordinator declared to the operations shift at T=7 minutes an Unusual Event (UE). After declaring the event, the SM requested additional information from the operations shift and after additional information was presented to the SM, the SM changed the classification level to the correct classification level, Alert, at T=10 minutes.

The scenario expectation was that only an Alert would be declared, although both the UE EAL threshold and Alert thresholds were exceeded. Because guidance is not clear on how to evaluate a scenario where a subsequent classification is made within 15 minutes of the conditions being available, the licensee reached out to industry subject matter experts. The results were as follows:

- Three individuals concluded: 2 for 2 – the UE declaration was a process error and critiqued, but the Alert declaration was timely and accurate, as was the Alert declaration.
- Three individuals concluded: 2 for 3 – the UE declaration was an unexpected and inaccurate declaration based on the available indications at the time. If the Earthquake Force Monitor (EFM) had been looked at it, it would have been noted that it indicated greater than the Alert level threshold, 0.2g, at 1055.
- One individual concluded: 3 for 4 – the UE was accurate based on the information known at the time; the UE notification was not done and therefore, not timely. The Alert classification and notification were both timely and accurate.
- One individual concluded: 3 for 3 successful opportunities. The UE was accurate based on the information available to the SM at the time. The Alert classification was timely and accurate within 15 minutes of the first indication of an earthquake. The notification was timely and accurate because it was within 15 minutes of the first declaration.

The licensee reviewed current guidance and industry input and graded the Alert classification as a pass. The SM was remediated through the corrective action program for the UE declaration. The results were 2 for 2 (timely and accurate Alert classification and timely Notification within 15 minutes of the Unusual Event declaration).

During Diablo Canyon's Evaluated Exercise week, the NRC reviewed the performance indicator per NRC Inspection Procedure 71151. The inspectors concluded the result was 1 for 2 successful opportunities. This conclusion, different from all 4 industry conclusions, appears to be based on guidance where a subsequent and correct EAL is not recognized within 15 minutes of availability. The reason that the classification is not an opportunity is that the appropriate classification level was not attained in a timely manner. However, in the scenario at DCPP, the correct EAL was recognized within 15 minutes.

This condition and others, such as when a scenario is designed where a developer may ramp a process value through a lower emergency classification trigger point (T=0) to a final higher value classification, the lower emergency classification is declared and then modified to the higher classification all within 15 minutes, prompt the need for consistent guidance on how these conditions are scored to ensure the extent of all possible conditions is considered once in this FAQ.

What is the NRC resident inspector's position?

The NRC's EP inspector believed the Alert classification is not counted in the PI and graded the scenario as 1 for 2 (inaccurate UE declaration, timely and accurate notification)

Potentially relevant existing FAQ numbers

None

Response Section

Proposed Resolution of FAQ:

Count as a successful opportunity the subsequent classification recognized and declared accurately within 15 minutes of the original initiating condition and/or when conditions became available to operators. Critique and enter the inadvertent or inaccurate classification in the station's corrective action program. Revise NEI 99-02 as shown below.

Proposed revision to NEI 99-02, Rev. 6, page 46, added to the existing paragraph beginning on line 43:

If the accurate and expected classification is recognized within 15 minutes of the original initiating condition or when conditions became available to operators, then the final classification shall be considered a success and shall be the only opportunity considered in the performance indicator. Any unexpected classification shall be entered in the station's corrective action program and is considered a non-opportunity.

Final NRC Response

The DEP PI statistic is intended to be a test of the licensee's decision maker's ability to make an accurate and timely declaration of an emergency event occurring on site. For this to happen the PI affords 15 minutes from the time the information is available to the decision maker, to the point the declaration decision needs to be completed. 10 CFR 50 Appendix E.IV.C.2 states:

By June 20, 2012, nuclear power reactor licensees shall establish and maintain the capability to assess, classify, and declare an emergency condition within 15 minutes after the availability of indications to plant operators that an emergency action level has been exceeded and shall promptly declare the emergency condition as soon as possible following identification of the appropriate emergency classification level. Licensees shall not construe these criteria as a grace period to attempt to restore plant conditions to avoid declaring an emergency action due to an emergency action level that has been exceeded. Licensees shall not construe these criteria as preventing implementation of response actions deemed by the licensee to be necessary to protect public health and safety provided that any delay in declaration does not deny the State and local authorities the opportunity to implement measures necessary to protect the public health and safety.

It is the expectation of the NRC staff that once the licensee decision marker announces the declaration, the decision has been made and should be evaluated base on its accuracy and timeliness (see EPFAQ 2012-002 ADAMS ML12333A281).

NRC Resolution of FAQ

EPFAQ 2012-002 defines the classification clock as beginning when indications are available to the licensee of an emergency action level (EAL) having been met or exceeded and stops when the licensee promptly declares the emergency condition. Since the EAL announcement ends the declaration classification portion of the DEP classification opportunity, the DEP opportunity would be counted as a failure because the declaration was announced incorrectly as a NOUE.

For a scenario in which a correct EAL declaration is made and then changed to an incorrect EAL within the original 15 minute declaration window, it follows that the initial notification of the incorrect EAL classification shall be considered inaccurate for the event and would be counted as a DEP notification PI failure.

Revision to NEI 99-02, Rev. 7, page 48, added to the existing paragraph beginning on line 31:

When a licensee decision maker announces the declaration of an EAL, the DEP classification opportunity is considered complete for both accuracy and timeliness (See EPFAQ 2012-002, ADAMS ML12333A281). Any subsequent change made to an incorrect or correct declaration within the 15 minute declaration window would not alter the determination of the DEP classification opportunity as a failure or success, respectively. Additionally, if a correct declaration is changed to an incorrect declaration within the 15 minute declaration window, then the initial notification of the incorrect EAL classification shall be considered inaccurate for the event and thus a DEP notification failure.

Effective Date

This FAQ is effective immediately for Diablo Canyon. For other licensees, the changes to NEI 99-02 will be effective on April 1, 2014, meaning that licensees will begin applying this FAQ resolution to 2Q2014 data reported to NRC in July 2014.

NRC Final Response
FAQ 13-05
Oyster Creek Downpower

Plant: Oyster Creek Nuclear Generating Station

Date of Event: 09/28/2012

Submittal Date:

Licensee Contact: Dennis M Moore **Tel/Email:** 609-971-4281 dennis.moore@exeloncorp.com

NRC Contact: Jeffrey Kulp **Tel/Email:** 609-971-4978

Performance Indicator: UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS (IE03)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: **when approved.**

Question Section

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

Page 13

Unplanned changes in reactor power are changes in reactor power that are initiated less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater than 20% of full power to resolve. Unplanned changes in reactor power also include uncontrolled excursions of greater than 20% of full power that occur in response to changes in reactor or plant conditions and are not an expected part of a planned evolution or test.

Page 14

Equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair are not counted as part of this indicator if they are repaired during the planned power reduction. However, if during the implementation of a planned power reduction, power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred.

Event or circumstances requiring guidance interpretation:

On September 28,' 2012 at 1802- Oyster Creek Nuclear Generating Station (OCNGS) experienced an increase in leakage from a previously identified (<72 hours) salt water leak into the condenser bay from a hole in circulating water piping. The timeline of power changes and event details are as follows:

1855 - Control Room Operators commenced lowering power to allow isolating and draining of the 1A North Condenser waterbox to mitigate the leakage of water into the condenser bay.

1914 – GenManager Ticket Number 1022326 was created to track the emergent downpower to 85%. The ticket begin time was 1901 with an end time of 2259 (the ticket was created, as such, with the intention of merging the repair with the upcoming planned downpower to 73%).

1927 - The power reduction was complete with Reactor Power at 85%.

1943 – The 1A North Condenser waterbox was isolated reducing the leakage to approximately half of the initial leakage.

2110 - Operations commenced draining 1A North waterbox

2147 – Operations completed a pre-job brief for lowering reactor power to 73% for "End of Cycle Rod Maneuvers"

2305 – Control Room Operators commenced lowering power from 85% to 73% for "End of Cycle Control Rod conditioning maneuver" (This is the beginning of a planned, >72 hours in advance, downpower to lower power to 73% from 9/28, 2300 until 9/29, 0700)

9/29, 0015 – Control Room Operators completed lowering power to 73%.

9/29, 0033 – Control Room Operators commenced raising power for "End of Cycle Control Rod conditioning"

9/29, 0041 – The initial repair to the 1A North Condenser waterbox piping was complete reducing the leakage from the waterbox to approximately 1 gpm.

9/29, 0116 – A decision was made to hold the power ascension (with power at 80%) to further assess the salt water leak prior to returning to 100% power

09/29, 0217 – Operations completed a pre-job brief for lowering power to 70% to aid in completing additional circulating water piping repair to reduce or eliminate leakage. (70% was chosen to provide more repair options)

09/29, 0302 – Control Room Operators commenced lowering power from 80% to 70% to "Repair leak Circ Water Leak"

09/29, 0335 – Control Room Operators completed lowering power to 70%

09/29, 0335 to 09/29, 1539 – OCNGS took action, as required, to aid in repairing the circulating water leak.

09/29, 1539 – Circulating water repairs are complete and Control Room Operators commenced raising reactor power from 70% to 100%

09/29, 1843 – Reactor power was returned to 100%

As noted above, Oyster Creek lowered power emergently (<72 hours) due to a salt water leak- with an initial power reduction to 85% (<20% reduction). Power was then lowered to 73% at 0015 in accordance with a planned (>72 hours) power maneuver. After completion of the planned power maneuver, during power ascension (at approximately 80%) a decision was made to lower power to 70% power to facilitate additional repairs to the circulating water system to attempt to eliminate leakage. 70% power was chosen to allow securing of a circulating water pump to increase repair options. (It is important to note that the repair could have been made at a power level above 70%.)

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

<u>NRC Resident Comments</u>

The description of the event and subsequent plant response is accurate as presented.

The NRC resident inspection staff does not agree that the guidance provided in NEI 99-02 excludes the duration of a downpower from consideration when determining whether a downpower should count against this performance indicator. NEI 99-02 revision 6, page 14, lines 10-14 state:

> "Equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair <u>are not counted as part of this indicator if they are repaired during the planned power reduction</u>. However, if during the implementation of a planned power reduction, power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred."

NRC Final Response
FAQ 13-05
Oyster Creek Downpower

The NRC resident inspection staff determined that this downpower should count for the following reasons:

- The initial downpower was due to address an off-normal condition (the leak on the circulating water piping) and occurred approximately 4 hours before scheduled power reduction for control rod conditioning.
- The licensee reduced power by a total of 30% to perform the repair and resolve the equipment problem.
- The equipment problem was not repaired during the planned power reduction.

Licensee Position

An emergent downpower to 85% was initiated to address circulating water piping leak. The emergent downpower was scheduled to coincide with a planned downpower to 73% for End of Cycle Rod Maneuvers (rod pattern adjustments). Repairs commenced during the emergent downpower and continued into the planned power reduction significantly reducing the leakage (to approximately 1 gpm). The emergent downpower was < 20 and therefore outside the scope of the performance indicator.

During power ascension from the planned power reduction for rod pattern adjustments, a decision was made to halt the power ascension at 80%, reduce power to 70%, and perform additional repairs to further reduce or eliminate leakage from the circulating water piping repair prior to returning to 100% power.

- The power reduction to 70% was outside of the preplanned evolution which ended at 0033 on 9/29/12
- The power reduction to 70% was < 20% below the previous power level of 80%
- A power reduction to 70% was not required for the additional repairs
- Power level had not been restored to 100% following completion of the planned power reduction.

Potentially relevant existing FAQ numbers: None

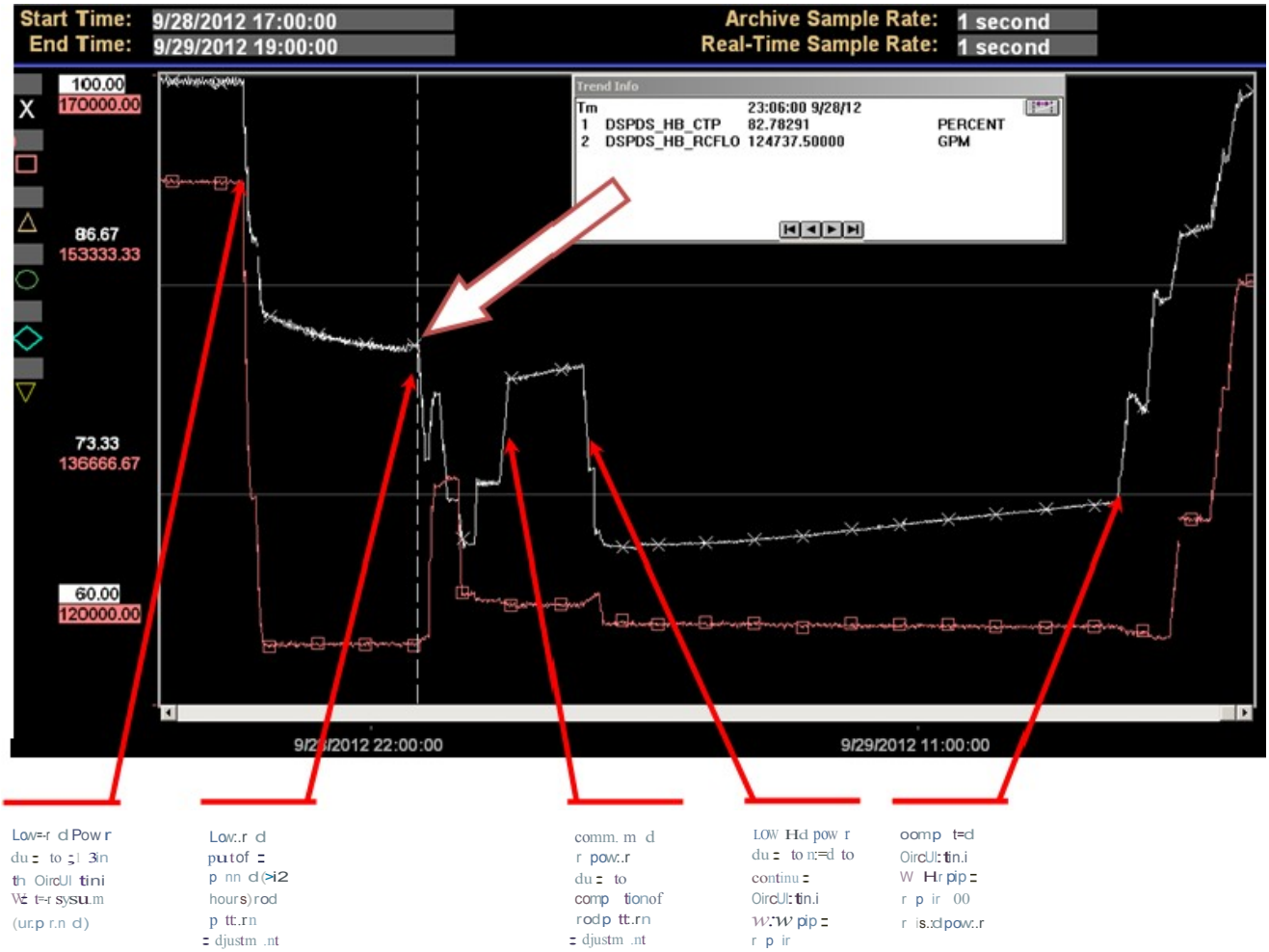
Response Section

Proposed Resolution of FAQ

The emergent and preplanned power reduction should be evaluated as two power reductions as opposed to one continuous power reduction to 73%. The power reduction from 80 to 70 should not be counted as an unplanned power reduction since it was not >20% from the preplanned or the previous power level.

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

Attachment 1 – Reactor Power vs Time



NRC Response

The licensee is requesting interpretation of NEI 99-02 guidance as applied to their particular donwpower event. The current guidance in NEI 99-02, Rev. 7 was incorporated by FAQ 469 (Sept. 2009) that changed the definition of unplanned power changes to the following:

NEI 99-02 Rev.7, Page 13

Unplanned change~~s~~ in reactor power, for the purposes of this indicator, ~~are~~ is a change~~s~~ in reactor power that (1) ~~are~~ was initiated less than 72 hours following the discovery of an off-normal condition that required or resulted in a power change~~, and that result in, or require a change in power level~~ of greater than 20% of full power to resolve, and (2) has not been excluded from counting per the guidance below. Unplanned changes in reactor power also include uncontrolled excursions of greater than 20% of full power that occur in response to changes in reactor or plant conditions and are not an expected part of a planned evolution or test.

The licensee concludes that the event should be excluded from counting as an Unplanned Power Change per 7,000 Critical Hours per the following guidance:

NEI 99-02, Rev. 7, Page 15

15 Equipment problems encountered during a planned power reduction greater than 20% that alone
16 may have required a power reduction of 20% or more to repair are not counted as part of this
17 indicator if they are repaired during the planned power reduction.

The NRC staff concludes that this event meets the first part of the definition of unplanned changes in reactor power since the down power was initiated less than 72 hours following the discovery of a circulating water leak and resulted in a total power reduction of 30% (100% to 70%) of full power to fully resolve.

The staff also concludes that the exclusion (NEI 99-02, Rev. 7, page 15, lines 15-17) does not apply based on the specific circumstances of the event, particularly because the equipment problem drove operators to lower power earlier than originally planned. The staff's conclusion is that this event meets the guidance in NEI 99-02, Rev. 7, as an Unplanned Power Change per 7,000 Critical Hours performance indicator occurrence.

The staff believes that the exclusion as written doesn't have sufficient detail on when an equipment problem should be counted toward the PI. The guidance (NEI 99-02, Rev. 7, page 15, lines 15-17) is difficult to apply because the intent is ambiguous (i.e., why is credit being granted when otherwise the occurrence by itself would count against the PI). The staff recommends modifying the guidance to provide a clear understanding of the basis for applying the guidance.

This FAQ is effective immediately after approval.

Final NRC Response
FAQ 13-04
Point Beach Alert & Notification System

Plant: Point Beach 1 and Point Beach 2
Date of Event: May 15, 2013
Submittal Date: August 14, 2013
Licensee Contact: Gerard D. Strharsky **Tel/email:** 920-755-6557
NRC Contact: James Beavers **Tel/email:** 630-829-9760

Performance Indicator: Alert and Notification System Reliability (EP03)

Site-Specific FAQ (Appendix D)? Yes, Appendix D page D-1

32 **Kewaunee and Point Beach**
33
34 Issue: The Kewaunee and Point Beach sites have overlapping Emergency Planning Zones (EPZ).
35 We report siren data to the Federal Emergency Management Agency (FEMA) grouped by criterion
36 other than entire EPZs (such as along county lines). May we report siren data for the PIs in the
37 same fashion to eliminate confusion and prevent 'double reporting' of sirens that exist in both
38 EPZs? Kewaunee and Point Beach share a portion of EPZs and responsibility for the sirens has
39 been divided along the county line that runs between the two sites. FEMA has accepted this, and
40 so far the NRC has accepted this informally.
41
42 Resolution: The purpose of the Alert and Notification System Reliability PI is to indicate the
43 licensee's ability to maintain risk-significant EP equipment. In this unique case, each neighboring
44 plant maintains sirens in a different county. Although the EPZ is shared, the plants do not share
45 the same site. In this case, it is appropriate for the licensees to report the sirens they are
46 responsible for. The NRC Web site display of information for each site will contain a footnote
47 recognizing this shared EPZ responsibility.

FAQ requested to become effective when <u>approved</u>.

Question Section:

NEI 99-02 Guidance needing interpretation (include page and line citation):
Page D-1 Lines 45 and 46. "In this case, it is appropriate for the licensees to report the sirens they are responsible for."

Event or circumstances requiring guidance interpretation:
Point Beach Nuclear Plant (PBNP) personnel have been notified that as a result of the Kewaunee Power Station (KPS) decommissioning actions, KPS will no longer be monitored under the NRC Reactor Oversight Process (ROP). On May 15, 2013 the NRC docketed KPS's certification of permanent defueling. Pursuant to10 CFR 50.82(a)(1)(ii), the 10 CFR Part 50 license for KPS no longer authorizes operation of the reactor or emplacement or retention of fuel into the reactor vessel, as specified in 10 CFR 50.82(a)(2). All data collection for CDE and INPO shall be counted from the beginning of May until May 15, 2013 @ 1358.

This situation results in a condition where neither KPS nor PBNP are reporting NEI 99-02 ANS PI data for the eight overlapping sirens located in Kewaunee County. The sirens are still the responsibility of and

are being maintained by KPS as required by 10CFR50.47 and 10CFR 50 Appendix E. Because KPS retains responsibility for the sirens, PBNP is not reporting PI data as outlined in current NEI 99-02 guidance. This condition will exist until PBNP installs new or assumes responsibility for the existing overlapping sirens. PBNP understands that it is the licensee's responsibility to ensure ANS sirens remain available and are not impacted by the KPS decommissioning process. PBNP also understands that KPS will be submitting an exemption that would no longer require a Public Alert and Notification System (ANS siren equipment) when they transition to a fully decommissioned, this is expected to occur one year to seventeen months from the May 15, 2013 permanent defueled date.

PBNP has historically, and will continue to, obtain ANS siren performance and maintenance records and data from KPS for the purpose of monitoring and recording all required information related to overlapping siren performance.

If licensee and NRC resident/region do not agree on the facts and circumstances explain
The content of this FAQ has been reviewed with NRC Region III Emergency Preparedness Inspector Mr. James Beavers. Mr. Beavers indicated that he concurs with the facts and circumstances as provided.

Potentially relevant existing FAQ numbers
None

Response Section

Proposed Resolution of FAQ
Until such time as KPS is no longer responsible for the 8 ANS sirens that are co-located in Kewaunee County and are within the PBNP EPZ, PBNP will document siren performance for these 8 sirens in the comments section of the Point Beach Unit 1 and Unit 2 Emergency Preparedness performance indicator (Total sirens-tests), in the INPO Consolidated Data Entry data base. When PBNP becomes responsible for the maintenance and testing of sirens located in Kewaunee County, revise NEI 99-02 Rev. 6 Appendix D to remove the "Kewaunee and Point Beach" plant specific design issue from the document. PBNP will subsequently commence reporting of siren performance for all sirens within the PBNP EPZ as required by the ROP and NEI 99-02.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
No wording change is required.

NRC Final Response

The staff agrees with the Proposed Resolution and an effective date of April 2, 2014.

NRC Final Response
FAQ 13-06 Dresden MSPI

Plant:	**Dresden Units 2 & 3**		
Date of Event:	**5/22/12 & 6/10/12**		
Submittal Date:	**8/30/13**		
Licensee Contact:	**Joshua Smith**	Tel/Email:	**815-416-3848 / Joshua.Smith3@exeloncorp.com**
NRC Contact:	**Chuck Phillips**	Tel/Email:	**630-829-9752 / Charles.Phillips@nrc.gov**

Performance Indicator: **MSPI**

Site-Specific FAQ (Appendix D)? **No**

FAQ requested to become effective **when approved**.

Question Section

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

Per NEI 99-02, Rev. 6 under Unplanned Unavailable Hours on page F-5:

> "Unplanned unavailable hours: These hours include elapsed time between the discovery and the restoration to service of an equipment failure or human error (such as a misalignment) that makes the train unavailable. Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s). In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process. **Unavailable hours to correct discovered conditions that render a monitored component incapable of performing its monitored function are counted as unplanned unavailable hours.** An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that was determined to have resulted in the equipment being non-functional even though no demand or failure actually occurred. Unavailability due to mis-positioning of components that renders a train incapable of performing its monitored functions is included in unplanned unavailability for the time required to recover the monitored function."

Per NEI 99-02, Rev. 6 under Planned Unavailable Hours on page F-5:

> "Planned unavailable hours: These hours include time a train or segment is removed from service for a reason other than equipment failure or human error. **Examples of activities included in planned unavailable hours are preventative maintenance, testing, equipment modification, or any other time equipment is electively removed from service to correct a degraded condition that had not resulted in a loss of function.** Based on the plant history of previous three years, planned baseline hours for functional equipment that is electively removed from service but could not be planned in advance can be estimated and the basis documented. When used in the calculation of UAI, if the planned unavailable hours are less than the baseline planned unavailable hours, the planned unavailable hours will be set equal to the baseline value."

Per NEI 99-02, Rev. 6 under Train Unavailable Hours on page F-5:

> "Train unavailable hours: The hours the train was not able to perform its monitored function while critical. Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's monitored functions. **In all cases, a train that is considered to be OPERABLE is also considered to be available.** Unavailability must be by train; do not use average unavailability for each train because trains may have unequal risk weights."

Per NEI 99-02, Rev. 6 under Unavailability on page 31:

> "Unavailability is the ratio of the hours the train/system was unavailable to perform its monitored functions (as defined by PRA success criteria and mission times) due to planned and unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters. (Fault exposure hours are not included; unavailable hours are counted only from the time of discovery of a failed condition to the time the train's monitored functions are recovered.) Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s). **In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue.** If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process."

Event or circumstances requiring guidance interpretation:

On 5/22/12 at Dresden Unit 2 and 6/10/12 at Dresden Unit 3, minor steam leaks were discovered on elbows for the High Pressure Coolant Injection (HPCI) System Drain Pot Line. The purpose of this line is to provide a drainage path for any condensation that forms at steam isolations while the system is in standby. The line is isolated from the system upon initiation and not required for the system to perform its safety functions. This line of piping is ASME Code Class 2 piping and, per the Dresden Technical Requirements Manual (TRM), requires the structural integrity be restored or the component isolated immediately if the boundary is not in conformance. In order to isolate this portion of piping, the inboard and outboard steam isolation valves (2301-4/5) must be closed, thus isolating the entire HPCI system from steam and making it unavailable. The system remained operable and available prior to the steam supply valves being closed.

When reporting the unavailability for the Mitigating System Performance Index (MSPI), Dresden Station considered this unavailability to be Planned Unavailability based on the definitions provided in NEI 99-02 referenced above. The station counted the unavailability as planned since the system was still capable of performing its monitored function with the leak; i.e. the leaking component is not a monitored component and the monitored function of providing a source of high pressure make-up water to the Reactor Vessel (per the Reactor Oversight Program MSPI Bases Document for Dresden Nuclear Generating Station, Rev. 9, Nov. 2011 under Section 2.2) was not lost. This aligns with the above section from NEI 99-02 discussing unplanned unavailable hours.

On 4/25/13, a Regional NRC Inspector questioned the station on how it applied the MSPI unavailability. The NRC Inspector believes that the station did not remove the equipment from service electively due to

the TRM requirement and, therefore, the unavailability should be counted as unplanned per the above section from NEI 99-02 discussing planned unavailable hours.

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

The facts and circumstances are agreed upon. The only point of contention is whether the unavailability detailed above should be counted as planned or unplanned based on the interpretation of NEI 99-02.

Response Section

Proposed Resolution of FAQ
Revise the sections of NEI 99-02 that affect the interpretation of planned versus unplanned unavailability to make it clear that anytime there is not a failure of a monitored component /function, the unavailability is considered to be planned.

NEI 99-02, Rev. 6, page F-5, beginning at line 24:

Planned unavailable hours: These hours include time a train or segment is removed from service for a reason other than **a condition within the train/segment boundary that renders the train/segment unavailable.** Examples of activities included in planned unavailable hours are preventive maintenance, testing, equipment modification, or any other time **equipment is removed** from service to correct a degraded condition that had not resulted in loss of function. Based on the plant history of previous three years, planned baseline hours for functional equipment **that is removed from service** but could not be planned in advance **(e.g., predictive maintenance)** can be estimated and the basis documented. When used in the calculation of UAI, if the planned unavailable hours are less than the baseline planned unavailable hours, the planned unavailable hours will be set equal to the baseline value.

Unplanned unavailable hours: These hours include elapsed time between the discovery and the restoration to service of an equipment failure, **condition** or human error (such as a misalignment) **that results in a loss of function. Time of discovery is when the licensee** determines that a failure has occurred or when an evaluation determines that the **train/segment** would not have been able to perform its monitored function(s). In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process. Unavailable hours to correct discovered conditions that render a monitored component incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that was determined to have resulted in the equipment being non-functional even though no demand or failure actually occurred. Unavailability due to mis-positioning of components that renders a train incapable of performing its monitored functions is included in unplanned unavailability for the time required to recover the monitored function.

NRC Response

During the ROP Working Group meeting on November 21, 2013, the licensee indicated that the monitored function of the HPCI system would not be lost if a complete shear of the HPCI steam pot drain line were to occur. Since the monitored function of the HPCI system (single train) was

supported, the unavailability as a result of removing the system from service to support repair of the leaks on the steam pot drain line is considered planned unavailability.

In addition to the licensee's proposed resolution to the FAQ, the NRC staff wants to clarify in the NEI 99-02 guidance that a failure of an unmonitored component within the system's boundary can cause unplanned unavailability to accrue if the failure results in a loss of the monitored function of the system/train/segment.

The staff recommends the following changes to NEI 99-02, Rev. 7, page F-6, beginning at line 23:

Planned unavailable hours: These hours include time a train or segment is removed from service for a reason other than **a condition within the system/train/segment boundary that renders the train/segment unavailable to perform its monitored function.** Examples of activities included in planned unavailable hours are preventive maintenance, testing, equipment modification, or any other time **equipment is removed** from service to correct a degraded condition that had not resulted in loss of function. ~~Based on the plant history of previous three years, planned baseline hours for functional equipment **that is removed from service** but could not be planned in advance **(e.g., predictive maintenance)** can be estimated and the basis documented.~~ When used in the calculation of UAI, if the planned unavailable hours are less than the baseline planned unavailable hours, the planned unavailable hours will be set equal to the baseline value.

Unplanned unavailable hours: These hours include elapsed time between the discovery and the restoration to service of an equipment failure, **condition,** or human error (such as a misalignment) **that results in a loss of the monitored function. Time of discovery is when the licensee** determines that a failure has occurred or when an evaluation determines that the **train/segment** would not have been able to perform its monitored function(s). In any case where a monitored **or unmonitored** component **within the system's boundary** has been declared inoperable ~~due to~~ **because of** a degraded condition, if the ~~component~~ **train/segment** is considered available, there must be a documented basis for that determination, otherwise a ~~failure~~ **loss of the monitored function** will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process. Unavailable hours to correct discovered conditions that render a ~~monitored~~ **train/segment** ~~component~~ incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that was determined to have resulted in the equipment being non-functional even though no demand or failure actually occurred. Unavailability due to mis-positioning of components that renders a train**/segment** incapable of performing its monitored functions is included in unplanned unavailability for the time required to recover the monitored function.

The FAQ effective date will be immediate once approved (01/15/2014).

FAQ 13-03
Quad Cities Animal Intrusion
(NRC Final Response)

Plant: Quad Cities
Date of Event: June 5, 2013
Submittal Date: August 16, 2013
Licensee Contact: Jason Smith **Tel/email**: jason.smith@exeloncorp.com
NRC Contact: Brian Cushman **Tel/email:** brian.cushman@nrc.gov

Performance Indicator: Unplanned Power Changes per 7,000 Critical Hours (IE03)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: when approved

Question Section

Question #1 -What is considered reasonable for prevention of animal intrusion? Would turning off the lights in a switchyard without motion sensors and an intact boundary still be considered reasonable to prevent animal intrusion?

Question #2 – When does the anticipated outcome of an event apply for PI reporting? If during the review of an event, new information is discovered that validates plant response during the event, can that new information be applied to consider the plant response anticipated even though operators were challenged by unanticipated plant response at the time?

NEI 99-02, Rev. 7 Guidance needing interpretation (include page and line citation):

Page 15, line 19-28
19 Anticipated power changes greater than 20% in response to expected environmental problems
20 (such as accumulation of marine debris, biological contaminants, or frazil icing) which are
21 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be
22 counted unless they are reactive to the sudden discovery of off-normal conditions. However,
23 unique environmental conditions which have not been previously experienced and could not
24 have been anticipated and mitigated by procedure or plant modification, may not count, even if
25 they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of
26 marine or other biological growth from causing power reductions. Intrusion events that can be
27 anticipated as part of a maintenance activity or as part of a predictable cyclic behavior would
28 normally be counted unless the down power was planned 72 hours in advance.

Page 16, line 39-43
39 For an environmental event to be excluded, any of the following may be applied:
40 • If the conditions have been experienced before and they exhibit a pattern of
41 predictability or periodicity (e.g., seasons, temperatures, weather events, animals, etc.),
42 the station must have a monitoring procedure in place or make a permanent modification
43 to prevent recurrence for the event to be considered for exclusion from the indicator. If

Event or circumstances requiring guidance interpretation:
On June 5, 2013 an animal (raccoon) caused a fault on a 13.8 kV bus located in the Quad Cities switchyard near Transformer 82, when the animal contacted one phase and part of the metal structure. The Unit 2 reserve aux transformer (RAT) tripped from service, as expected, and a fast bus transfer occurred to

preclude a load trip due to undervoltage. This fault resulted in the loss of a bus in the switchyard. By procedure, when this bus is lost, operators are directed to reduce Unit 2 to approximately 85% power for transformer loading concerns on the unit auxiliary transformer (UAT). During the downpower, in response to the loss of the transformer, reduced feedwater temperature was observed by the control room operators. In response to the reduced feedwater heating, power was reduced to about 60% in accordance with approved procedures. Operator monitoring and response was consistent with their training and in accordance with approved station procedures.

Licensee management has determined that this event is not reportable because the transient was initiated by an animal intrusion event and the lower than anticipated final power was not the result of an equipment failure or human performance error.

The NRC resident inspectors consider this event reportable because the licensee began turning off the lights in the switchyard at night. Without lighting, the conditions in the switchyard were no longer reasonable to prevent animal intrusion. Also, by training and annunciator response, the anticipated power reduction for a loss of the Unit RAT would be about 85% power. The loss of feedwater heating, which was unanticipated for this event at the time, was an additional 25% downpower that should be reported as a separate PI occurrence.

If licensee and NRC resident/region do not agree on the facts and circumstances explain:
The licensee and the NRC agree on the facts. The NRC and the licensee disagree on the applicability of reporting under the PI.

<u>The Licensee' s Position:</u>
Reasonable steps were taken to prevent the animal intrusion. The switchyard fence was in good repair and the gates were secured. Operations personnel perform a weekly walkdown of the switchyard and daily rounds in the switchyard on T82. This would identify degraded conditions and any signs of animal intrusion. Also, the switchyard is in a frequently traveled area next to the security checkpoint. A vegetation management program in also in place, which sprays the switchyard to prevent overgrowth. Consistent with the guidance in NEI 99-02 (referenced above) a plant modification was installed after this event. This change added wildlife deterrent devices to both transformers 81 and 82. These devices should prevent recurrence of animal intrusion. Given the level of human activity in the area, material condition of the switchyard, and a history of no animal intrusion issues, the licensee maintains that reasonable steps were taken and in place to prevent animal intrusion.

Of note, the decision to turn off lights in the switchyard was vetted with key stakeholders prior to implementation.

The loss of feedwater heating was due to the voltage transient on the instrument bus, as a direct result of the fault caused by the raccoon. The momentary lowering of voltage caused various feedwater heater solenoid valves to trip, resulting in feedwater heater level control valves unlatching. Operators responded to the transient in accordance with approved procedures.

The loss of feedwater heating could be expected to occur during a fault in the switchyard, depending on where the fault occurs. There have been faults in the past where all heaters have remained latched, and some faults where a partial loss of feedwater heating has occurred. In this event, the fault was sufficient to cause enough of a voltage transient that the feedwater heater latching solenoids dropped out. Operators

are trained on the loss of a Unit RAT and also trained on loss of feedwater heating. The operator responses for these two events are governed by approved procedures. There were no malfunctions of equipment or human performance errors that led to the additional 25% downpower.

The NRC's Position (Resident Inspector's Comments):

The NRC concurs that the switchyard fence was in good repair and there was no food or other materials in the switchyard. Licensee management made a decision to turn the lights in the switchyard off except for times of maintenance. There are no motion detectors in the switchyard. Lights have been on in the switchyard during the night for the purpose of theft deterrent. Licensee management did not assess if the lights in the switchyard also provided a deterrent to the local wildlife. Licensee management made this change to the switchyard lighting during the weekend of June 1, 2013, and on June 5, 2013, an animal causes a switchyard fault.

The NRC agrees that no equipment failed and no human performance errors occurred during this event that contributed to the extra 25% downpower. Indications were received by the control room operators for a loss of a Unit RAT. The additional loss of feedwater heating was unexpected and not anticipated to occur coincident with the loss of a Unit RAT. This fault occurred on the bus that feeds the transformer which resulted in the unlatching of several feedwater level control valves. This new information will be incorporated into operator response procedures and training materials.

It is the position of the NRC that prior to this event, the anticipated final plant condition for a loss of the Unit RAT is 85% power. For future events, with the inclusion of the possibility of partial loss of feedwater heating incorporated, the expected final power level may be lower. But for the purposes of reporting under this PI, the additional 25% power reduction should be reported as an unplanned power change.

Potentially relevant existing FAQ numbers:

ID 237– The response details taking actions outside of pre-planned activities.

Response Section

Proposed Resolution of FAQ

Proposed answer #1 – An intact switchyard fence in a frequently traveled area can be viewed as a reasonable barrier for the prevention of animal intrusion, with or without switchyard lighting being illuminated. Vegetation management practices were in place to ensure there was not an adequate habitat for raccoons or their food source to exist.

Proposed answer #2 – Since the reduction in power was solely due to an animal intrusion event, this event should not be reported, regardless of when the validation of plant response is determined. The plant operated as expected during the transient and the operators responding to the event took appropriate actions in accordance with approved procedures.

NRC Final Response

The staff reviewed IEEE Standard 1264-1993 (R2009), "IEEE Guide for Animal Deterrents for Electrical Power Supply Substations" to identify reasonable methods to prevent animal intrusion. The main methods identified in the standard are physical barriers, increased insulation, and other deterrents (fake predatory animals, disturbing noises, chemical repellents, and screening). The staff agrees that

an intact switchyard fence in a frequently traveled area can be viewed as a reasonable barrier for the prevention of animal intrusion, with or without lighting.

Since the event has not been experienced previously at Quad Cities and the intrusion event could not have been anticipated 72 hours in advance, the following exclusion in NEI 99-02 is applicable:

NEI 99-02, Revision 7 (Page 15, Lines 19-25)
Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted unless they are reactive to the sudden discovery of off-normal conditions. <u>However, unique environmental conditions which have not been previously experienced and could not have been anticipated and mitigated by procedure or plant modification, may not count, even if they are reactive.</u>

The staff agrees that this event should not be counted against the PI. The licensee is expected to take adequate corrective action to prevent similar intrusion events in the future.

This FAQ is effective immediately (11/20/2013).

FAQ 13-01 Final
Turkey Point Unplanned Scrams per 7000 Hours Critical

Plant: Turkey Point Unit 3
Date of Event: March 12, 2013
Submittal Date: March 14, 2013
Licensee Contact: Bob Tomonto Tel/email: 305-246-7327 bob.tomonto@fpl.com
NRC Contact: Tim Hoeg Tel/email: 305-246-6199 tim.hoeg@nrc.gov

Performance Indicator: IE01, Unplanned Scrams per 7000 Critical hours

Site-Specific FAQ (Appendix D)? YES

FAQ requested to become effective when approved.

This FAQ concerns the March 12, 2013 Turkey Point Unit 3 manual reactor trip. This trip was the third in four quarters and because the plant had accrued a low number of critical hours in that time period (approximately 4500), the NRC Performance Indicator IE01 exceeded the Green-White threshold of 3.0. Florida Power & Light (FPL), as licensee for Turkey Point Units 3 and 4, proposes that Performance Indicator IE01 be shown as "N/A" until Unit 3 has accumulated four full quarters of power operation so that the indicator will be representative of operational performance. The reason for this request is that the site was in a planned extended shutdown during the first three quarters of 2012 (2/26/12 - 9/6/12) to perform upgrades and plant improvements associated with an Extended Power Uprate (EPU). The low number of critical hours was not in any way related to poor operational or regulatory performance.

This request is being submitted as a Plant-Specific FAQ, as discussed in NEI 99-02, Appendix D, which states that the

> guidance was written to accommodate situations anticipated to arise at a typical nuclear power plant. However, uncommon plant designs or unique conditions may exist that have not been anticipated. In these cases, licensees should first apply the guidance as written to determine the impact on the indicators. Then, if the licensee believes that there are unique circumstances sufficient to warrant an exception to the guidance as written, the licensee should submit a Frequently Asked Question to NEI for consideration at a public meeting with the NRC.

Question Section

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

- NEI 99-02, Rev 6, Page 10 Lines 25-27.
- NEI 99-02, Rev 6, Page D-1 Lines 16-21.

Event or circumstances requiring guidance interpretation:

Between February 26, 2012 and September 6, 2012, Turkey Point Unit 3 was shutdown for extensive plant modifications and improvements required to support operation at increased power levels. The extended EPU shutdown resulted in a very low number of critical hours during the first three quarters of 2012. As a result of scrams during the first quarter of 2013, Unit 3 will end this quarter with NRC PI IE01 value of approximately 4.5, which is indicative of the volatility of the PI when the number of hours of critical operation is significantly below the 7000 hour reference value.

NEI 99-02, Revision 6 allows for displaying the IE01 value as "N/A" when accumulated critical hours are less than 2400. That is intended to prevent a unit from crossing from Green to White, based solely on a single unplanned scram. NEI 99-02, also clearly indicates that the indicator is monitored over four quarters of operation. Further, the Data Example table on page 11, shows no PI values until after four quarters of data are accumulated. In fact, the example in that table shows that greater than 2400 hours of critical operation had been accumulated in third quarter of 1997, with one scram, yet no PI value is displayed.

NRC Inspection Manual Chapter (IMC) 0351, "Implementation of the Reactor Oversight Process at Reactor Facilities in an Extended Shutdown Condition for Reasons Other Than Significant Performance Problems," acknowledges that even two quarters of operating data following a plant shutdown of longer than six months "makes this PI more volatile." NRC IMC 308, "Reactor Oversight Process (ROP) Basis Document," Attachment 1, Figure 1 provides the basis for using 7000 hours in the denominator is one year's worth of critical hours assuming an 80% capacity factor. In addition, Figure 1 also states that the Green to White threshold for PI IE01 was selected to "identify outliers from industry norms."

For Turkey Point Unit 3, the White threshold will be crossed because the denominator is below industry norm (7000 hours) due to the extended EPU outage, not because of the scrams. The unit did not operate for a full four quarters with a "normal" refueling outage and therefore should not be penalized with a significantly high PI because it is not representative of a reduction in safety margin and Turkey Point Unit 3 is not an outlier from industry norms.

A previously submitted White Paper from the NEI ROP Task Force proposed a similar approach for MSPI data. The basis is that the indicator value is heavily influenced by the number of hours of critical operation. When a plant is shutdown for extended outage (*i.e.*, greater than six months), the indicator may not give results that are representative of the intent of ROP. Consequently, it has been proposed that MSPI be "grayed out" for those plants that are shutdown for greater than six months and not be restored until after four quarters of operation have been accumulated.

With a greater than six month refuel outage and only a portion of third quarter 2012, fourth quarter 2012 and the first quarter 2013 with potential critical operating hours, the PI will not display representative values for Turkey Point Unit 3 and should be displayed as "N/A." The PI will not accurately represent plant operation until the full four quarters of plant operation have been accrued.

Potentially relevant existing FAQ numbers:

There are no potentially relevant FAQs. However, it should be noted that recent discussions with NRC staff regarding applicability of MSPI data that is skewed by extended plant shutdowns indicates that indicators that are tied to reactor critical hours may not be valid for shutdowns exceeding approximately 6 months and should not be actively monitored until four quarters after reactor restart.

Response Section

Propose that Turkey Point Unit 3 be granted exemption from the threshold of 3.0 unplanned scrams per 7000 hours critical because of the circumstances for the extended plant shutdown resulting in less than four full quarters of operation. The PI should be displayed as "N/A" on the NRC website until four full quarters of power operation following the extended EPU outage in 2012.

NRC Final Response

The Unplanned Scrams indicator is defined as the number of unplanned scrams during the previous four quarters, both manual and automatic, while critical per 7,000 hours. Current guidance in NEI 99-02 requires this PI to be reported when more than 2,400 critical hours are accumulated in the previous four quarters. The 2,400 critical hours limit is intended to prevent a unit from crossing the Green-White threshold on a single unplanned scram. Turkey Point Unit 3 accumulated 4,745 critical hours and three scrams in the previous four quarters.

The PI is normalized to 7,000 hours to account for approximately 73 days (80% availability factor) of shutdown time in four quarters. Since the PI is based on critical hours and number of scrams in the previous four quarters, low critical hours (<7,000) will cause a PI threshold to be exceeded with a lower number of scrams. The Green-White threshold was crossed based on a combination of both critical hours and the number of scrams at Turkey Point Unit 3.

The licensee is requesting an exemption for Turkey Point Unit 3 from the threshold of 3.0 unplanned scrams per 7,000 critical hours because of the circumstances for the extended plant shutdown resulting in less than four quarters of operation. The NEI 99-02 guidance was written to accommodate anticipated situations like this at a typical nuclear power plant. Appendix D of NEI 99-02 allows exemptions to be granted if *unique* conditions exist that have not been anticipated by the licensee. The NRC does not consider less than four quarters of critical

operation a unique condition. The NRC staff does not support granting Turkey Point Unit 3 an exemption to the Unplanned Scrams per 7,000 Critical Hours indicator's Green-White threshold.

This FAQ is effective immediately (06/28/2013).

Final NRC Response
FAQ 13-02
Susquehanna Power Change

Plant: Susquehanna
Date of Event: June 11, 2012
Submittal Date: June 14, 2013
Licensee Contact: John Tripoli Tel/email: 570-542-3100/jltripoli@pplweb.com
NRC Contact: Patrick Finney Tel/email: (570)542-3189 patrick.finney@nrc.gov

Performance Indicator: IE03

Site-Specific FAQ (Appendix D)? Yes

FAQ requested to become effective when approved

Question Section:

During a planned power reduction of greater than 20% to support a scheduled control rod pattern adjustment, Susquehanna Unit 1 operators encountered a potential equipment problem. To expedite investigation of the plant equipment issue, the operators chose to manually initiate a reactor recirculation system runback which reduced power to the target power level more rapidly than originally projected. Following the runback, and resolution of the potential equipment problem, the planned rod pattern adjustment activities were performed at the target power level within the planned time frame. Power ascension proceeded as planned. Should this rapid power reduction within the planned power reduction scope be counted as an unplanned power change per 7000 critical hours?

Event or circumstances requiring guidance interpretation:

Following the Susquehanna Unit 1 Refueling Outage completed on 6/7/12, during power ascension, on 06/11/12, a planned power reduction from approximately 90% (initial) to approximately 65% (final) was scheduled to perform a rod pattern adjustment evolution. The plan was established greater than 72 hours prior to the actual power reduction.

After, the planned power reduction began at approximately 85% power, plant operators initiated a manual reactor recirculation runback at approximately 84% power to limiter #2 in order to reduce condenser area radiation levels. The runback was necessary to rapidly decrease radiation levels to allow entry into the condenser area to locate the source of water identified on an area camera in the condenser area.

The condenser area water issue was identified and remedied within 15 minutes of entry. The cause was a condenser area sump drain valve.

The planned rod pattern adjustment continued and was completed within the planned time frame of approximately 3 hours from the initial power reduction to completion of the rod pattern adjustment. At that time the ramp up from 70% power began.

Final NRC Response
FAQ 13-02
Susquehanna Power Change

PPL did not classify this as an unplanned power change because the planned rod pattern adjustment continued and was completed within the planned time frame. The condenser water issue was investigated and resolved within the planned time frame of the rod pattern adjustment and at the same power level as the planned evolution. The rod pattern adjustment (planned activity) was successfully performed at the planned power level with no delay.
The question is whether or not interrupting the rod pattern adjustment and initiating a reactor recirculation system runback should count as an Unplanned Power Change per 7000 critical Hours" under NRC IMC 0305 "Operating Reactor Assessment Program" and the guidance in NEI 99-02 "Regulatory Assessment Performance Indicator Guideline" Revision 6.

NEI 99-02, Rev.6, page 13, lines 3 through 6, contain the following Purpose statement for this indicator:

"This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator measures the number of plant power changes for a typical year of operation at power."

Further, NEI 99-02, Rev.6, page 14, lines 10 through 14 state:

" Equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair are not counted as part of this indicator if they are repaired during the planned power reduction. However, if during the implementation of a planned power reduction, power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred."

Susquehanna Unit 1 was in the process of reducing power on 6/11/2013, at 21:35, for a planned rod pattern adjustment. See the load profile below for a comparison of the predicted power changes in blue and the actual power changes in red.

PPL Susquehanna concluded that this was not an unplanned power change because:

- The power reduction was greater than 20% and was planned greater than 72 hours in advance of the rod pattern adjustment. The planned reduction was from approximately 90% power to approximately 65% power.
- Shortly after commencing the planned power reduction, in response to a "Condenser Area Transfer Sump High Level alarm, plant operators initiated a manual reactor recirculation pump runback to limiter 2. The runback started at approximately 84% power and ended at approximately 62% power.
- The emergent condenser area issue was resolved quickly and operators completed the planned rod pattern adjustment. Although the planned evolution was briefly delayed it was completed. If the planned evolution had been canceled (not just briefly delayed) because of the emergent condition, this would be considered an unplanned power change.
- guidance from NEI 99-02, Rev. 6 page 14 discussed above provides the reasoning for this to not be an unplanned power change. Although the power change was greater than 20%, it was resolved during the planned power reduction window and the emergent issue did not require power to be reduced by more than 20% <u>beyond</u> the planned power reduction.

Therefore, an unplanned power change did not occur.

<u>Additional considerations</u>:

The power reduction to perform the rod pattern adjustment was a planned evolution with additional personnel supporting the normal shift compliment. Consistent with the purpose of this indicator, no challenge to safety systems occurred. Shift personnel were ready for a power reduction, a potentially significant problem arose, shift personnel took conservative action to place the plant in a status where nuclear and radiological safety was maximized, and the potentially significant problem was addressed in a matter of minutes rather than a potentially longer period of time with higher radiation exposure.

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

The following NRC Resident Inspector Position (with concurrence from RI/DRP/PB4) position was provided:

A) The inspectors considered the following NEI 99-02, Regulatory Assessment Performance http://meetings.nrc.gov/pmns/mtghttp://meetings.nrc.gov/pmns/mtgndicator Guideline, Revision 6, guidance deemed pertinent to this discussion:

1) Page 13, Lines 9-10: The purpose of IE03 is to monitor "the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions."

2) Page 13, Lines 25-29: The term *Unplanned changes in reactor* power is defined as "changes in reactor power that are initiated less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater than 20% of full power to resolve. Unplanned changes in reactor power also include uncontrolled excursions of greater than 20% of full power that occur in response to changes in reactor or plant conditions and are not an expected part of a planned evolution or test."

3) Page 14, Lines 10-14: "Equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair are not counted as part of this indicator if they are repaired during the planned power reduction. However, if during the implementation of a planned power reduction, power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred.

4) Page 14, Lines 16-18: "Unplanned power changes and shutdowns include those conducted in response to equipment failures or personnel errors and those conducted to perform maintenance. They do not include automatic or manual scrams or load-follow power changes."

5) Page 14, Lines 23-24: "Unplanned power changes include runbacks and power oscillations greater than 20% of full power."

6) Page 16, Line 14: "Downpowers of greater than 20% of full power for ALARA reasons are counted in the indicator."

B) The inspectors considered the following information from PPL sources pertinent to this discussion:

Upon receipt of the sump alarm, the Operators used the Alarm Response Procedure, AR-125-001, Reactor and Turbine Bldg Miscellaneous Sumps Panel 1C692, Revision 8, according to operator logs. The procedure directs operators to "determine source of excessive inleakage and isolate as necessary" and "if excessive leakage is evident, perform ON-169-001." The following Off Normal Procedures were entered: ON-169-001, Flooding in the Turbine Building, ON-164-002, Loss of Reactor Recirculation Flow, and ON-178-002, Core Flux Oscillations. Operator logs on 6/11/12 at 2148 hours stated "Initiated Recirc Pump Runback to Limiter #2 in order to lower power to reduce Condenser Area Radiation Levels in support of a pending Condenser Area investigatory entry." The runback was reset at 2316 hours. Reactor power at that time was approximately 62 percent. PPL's investigation into the event determined this was a mispositioning event based on a valve found in the closed position.

Reactor Engineering staff were present for the control rod pattern adjustment evolution. Their Reactivity Manipulation Request was annotated with the comments "condenser area transfer sump Hi alarm. Downpower to ~60% by *unplanned power reduction* (emphasis added) form OP-AA-338-5." OP-AD-338-5 is the Controlled Shutdown/Unplanned Power Reduction form and has two means of entry: a controlled shutdown is required or an unplanned power reduction to below the reactor power maneuvering envelope. The copy used was annotated that a Transient was in progress and that a core flow reduction was required to mitigate the transient.

C) The inspectors questioned PPL's basis for not counting the downpower as unplanned. This is based on A(3) above in that the power reduction was not implemented as planned. Specifically, PPL's planned power reduction had not included a recirculation runback as part of the downpower sequence, was an interruption of the rod pattern adjustment, and was completed "more rapidly than originally projected." The resident inspectors also considered the runback a deviation from the planned power reduction based on the off-normal procedures entered as well as the procedure entered to implement the runback as described in B) above.

Based on the runback being a deviation from the downpower plan, the inspectors further considered the other NEI 99-02 entries described in A) above.

1) The annunciator alarm was due to a configuration control error where an operator mispositioned a condenser bay valve. The inspectors considered this information in light of reference A(4) above. Therefore, this was a personnel error that resulted in an operator response by reducing power >20%.
2) The operators inserted a recirculation runback in response to the alarm. The inspectors considered this information in light of reference A(5) above. Therefore, this was a runback >20% and unplanned power change.

3) Based on PPL operator logs, the runback was initiated to lower radiation levels in the condenser bay. Using reference A(6) above, the downpower occurred for ALARA reasons.
4) PPL's description of the event in the FAQ states, in part, that "the runback was necessary to rapidly decrease radiation levels." Based on reference A(1), the inspectors considered that the rapid reduction in power under other plant conditions could have challenged safety functions.
5) PPL discovered an off-normal condition that required a >20% power reduction to resolve and it was not an expected part of the planned rod pattern adjustment. Based on this and reference A(2) above, the runback was for an off-normal condition and was not an expected part of the planned evolution.

In summary, the power change that occurred was not planned as implemented. The downpower for a control rod pattern adjustment is normally executed through PPL's General Operating (GO) procedure and supporting Operations and Reactor Engineering procedures. In this case, PPL responded to an annunciator alarm resulting from a human performance mispositioning event by using Off Normal and Unplanned Power Reduction procedures and implemented a Recirculation Runback that resulted in a power change > 20%.

Potentially relevant existing FAQ numbers:

Archived FAQ's related to the Unplanned Power Changes per 7000 Critical Hours PI (IE03) were reviewed for applicability and consideration of the manner in which power was reduced. A direct correlation to this FAQ was not found. However, archived FAQs are not to be used as a reference for current situations. NEI 99-02, Rev. 6, Appendix E, page E-4 states:

"At the time of a revision of NEI 99-02, active FAQs will be reviewed for inclusion in the text. These FAQs will then be placed in an "archived" file. Archived FAQs are for historical purposes and are not considered to be part of NEI 99-02."

The currently approved IE03 FAQs (469 and 483) were reviewed and the changes proposed by these FAQ's are not applicable to the question posed by this FAQ.

Proposed Resolution of FAQ:

The resolution to this event should be to conclude that it should not be reported as an unplanned power change per 7000 critical hours.

Final NRC Response

Unplanned Power Changes per 7,000 Critical Hours performance indicator is defined as the number of unplanned changes in reactor power of greater than 20% of full-power, per 7,000 hours of critical operation excluding manual and automatic scrams. This indicator monitors power changes that could have, under other plant conditions, challenged safety functions. The cornerstone key attributes measured by the unplanned power changes PI are human error,

procedure quality, design, and equipment performance as referenced in Inspection Manual Chapter 0308, Attachment 1, "Technical Basis for Performance Indicators."

The definition of an *unplanned change in reactor power* is currently defined in FAQ 469 as follows:

> *Unplanned change in reactor power, for the purposes of this indicator, is a change in reactor power that (1) was initiated less than 72 hours following the discovery of an off-normal condition that required or resulted in a power change of greater than 20% of full power to resolve, and (2) has not been excluded from counting per the guidance below.*

The question posed by the licensee is whether the rapid power reduction (runback) event count in the Unplanned Power Changes per 7,000 Critical Hours performance indicator. The licensee concludes that the event does not count towards the PI because of the following guidance in NEI 99-02, Revision 6, page 14, lines 10-14:

> *Equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair are not counted as part of this indicator if they are repaired during the planned power reduction. However, if during the implementation of a planned power reduction, power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred.*

In addition, approved guidance in FAQ 469 provides examples of occurrences that are <u>not</u> counted toward the PI that include the following:

> *Unanticipated equipment problems that are encountered and repaired during a planned power reduction greater than 20% that alone could have required a power reduction of 20% or more to repair.*

The staff reviewed FAQ 231 to gain an understanding of the intent of the above guidance, which was first included in Revision 1 of NEI 99-02. The staff's interpretation of the Susquehanna event is that the off-normal condition (sump alarm) was not caused by an equipment problem (degraded condition) but by human error (measured cornerstone key attribute of the PI) since the condenser area sump valve (manual valve) was mispositioned by an operator. Also, the staff does not consider the manual repositioning of a valve an equipment repair. In addition, the staff considers the rapid power change following the condenser area sump alarm as an urgent and reactive operator response (using an off-normal procedure to initiate a runback) to an off-normal condition, and therefore, a deviation (method and rate of power reduction) from the already planned power change (rod pattern adjustment) that resulted in an <u>actual</u> change in reactor power level of greater than 20%. This event alone meets the definition of *unplanned changes in reactor power*. The staff's interpretation of the guidance in NEI 99-02, Revision 6, page 14, lines 10-14 was to exclude events related to equipment degradation that alone <u>may</u> have (indicates possibility) required reduction greater than 20% to resolve; the staff does not interpret the guidance to exclude all events that meet the PI definition occurring during a planned power reduction.

NEI 99-02 guidance (FAQ 469) provides examples of occurrences that would count toward this PI. This event meets the following examples:

Examples of occurrences that would be counted against this indicator include:

- *Power reductions that exceed 20% of full power and are not part of a planned and documented evolution or test. Such power changes may include those conducted in response to equipment failures or personnel errors or those conducted to perform maintenance.*

- *Runbacks and power oscillations greater than 20 % of full power. A power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% should be counted as two separate PI events, unless the power restoration is implemented using approved procedures. For example, an operator mistakenly opens a breaker causing a recirculation flow decrease and a decrease in power of greater than 20%. The operator, hearing an alarm, suspects it was caused by his action and closes the breaker resulting in a power increase of greater than 20%. Both transients would count since they were the result of two separate errors (or unplanned/non-proceduralized action).*

- *Unplanned downpowers of greater than 20% of full power for ALARA reasons.*

The staff concludes that this event counts as an occurrence toward the Unplanned Power Changes per 7,000 Critical Hours indicator for the following reasons:

- The off-normal condition was a result of human error and not equipment problems (degraded condition); therefore, the guidance in NEI 99-02, Revision 6, page 14, lines 10-14 does not apply to this event.

- A deviation (planned method and rate) from the planned power reduction (rod pattern adjustment) occurred because of an unrelated off-normal condition.

- An actual power reduction greater than 20% occurred.

- The event represents 3 examples that would otherwise count against the indicator.

The staff considers the guidance (NEI 99-02, Revision 6, page 14, lines 10-14) difficult to apply because of the ambiguity of the intent (i.e., why is credit being granted when otherwise the occurrence by itself would count against the PI). The staff recommends modifying the guidance to provide a clear understanding of the basis for applying the guidance.

This FAQ is effective immediately (10/23/2013).

NRC Final Response
FAQ 12-04, HRA Related Occurrences (Generic)

Plant: Perry
Date of Event: June 2, 2012
Submittal Date: August 16, 2012
Contact: John Pelcic **Tel/email:** 440-280-5824 jfpelcic@firstenergycorp.com
NRC Contact: Mark Marshfield **Tel/email:** 440-280-5822 mark.marshfield@nrc.gov

Performance Indicator: OR01 Occupational Exposure Control Effectiveness

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved. Approval date is May 8th, 2013.

Question Section

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

Page 62, Lines 16 - 22, and associated footnote

Technical Specification High Radiation Area (>1 rem per hour) Occurrence –
A nonconformance (or concurrent non-conformances) with technical specifications or comparable requirements in 10 CFR 20 applicable to technical specification high radiation areas (>1 rem per hour) that results in the loss of radiological control over access or work activities within the respective high-radiation area (>1 rem per hour). For high radiation areas (>1 rem per hour), this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10 CFR Part 20.

A footnote states that "Concurrent" means that the non-conformances occur as a result of the same cause and in a common timeframe.

Event or circumstances requiring guidance interpretation:

On June 2, 2012, an equipment failure resulted in resin/water slurry flow into the general area hallway of the Radwaste Building El. 574. Indications of changing radiological conditions were available. However, the Radiation Protection staff did not recognize the need to conduct a new radiological survey of the area, which was posted and controlled as a High Radiation Area (HRA) at the time. The failure to perform a timely radiological survey is a performance deficiency and an NRC Performance Indicator occurrence.

Over the next few days, there were two instances of individuals entering this area without Radiation Protection coverage and one instance where an individual was provided a HRA key but did not enter the area.

On June 7, 2012, a Radiation Protection technician performed a radiological survey of the area in preparation for decontamination activities. The survey identified a floor area where dose rates met the Technical Specification criteria for classification as a Locked High Radiation Area (LHRA). After the survey, the Radwaste Building El. 574 area was posted and controlled as a LHRA.

This PI counts non-conformances, or "concurrent non-conformances," with technical specifications. "Concurrent non-conformances" are defined as those that "occur as a result of the same cause and in a common timeframe." In this case, the three instances were as a result

of the same cause – the failure of Radiation Protection personnel to recognize the need to perform a new radiological survey. "Common timeframe" is not defined; however FENOC believes that these three instances meet the intent of a "common timeframe." The instances were a result of a single performance deficiency with the same common cause.

The failure to recognize the need to perform a new radiological survey prior to June 7, 2012, was reported as a PI occurrence. Additionally, the three instances of individuals entering the area, or having access without Radiation Protection coverage as a result of the single performance deficiency of not performing the timely survey were conservatively reported pending the outcome of this FAQ.

Since the PI counts non-conformances that "result in the loss of radiological control over access or work activities" and the nonconformance that led to the three entries was the failure of Radiation Protection to recognize the need to perform a new radiological survey, are the two subsequent entries and one potential entry considered to be "concurrent non-conformances" bounded by the failure to recognize the need to perform the new radiological survey?

What is the NRC resident inspector's position?

The NRC resident inspector agreed with the facts and recommended that the FAQ process be followed for resolution.

Potentially relevant existing FAQ numbers

FAQ 203 addresses the footnote in question. However, in FAQ 203, the causes of the two entries were different; therefore, both occurrences counted. FAQ 203 did not address "common timeframe."

Response Section

Proposed Resolution of FAQ

The failure to recognize the need to perform a new radiological survey represents a loss of control over access into a LHRA. However, since the subsequent three instances without Radiation Protection control were a result of the failure to perform the new radiological survey, and were within a limited common timeframe, they can be considered to be "concurrent non-conformances." Only one Technical Specification High Radiation Area PI occurrence should be reported.

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

In the footnote defining "concurrent," "common timeframe" should be defined to be "within the normal period of time between surveys for the specific area."

NRC Response

The proposed FAQ correctly quotes the applicable guidance in NEI 99-02 for this event. The performance indicator identifies an occurrence of non-conformance (or concurrent non-conformances) with technical specifications involving a loss of radiological controls over entries to (or work within) a Technical Specification High Radiation Area (TSLHRA, > 1 rem per hour). The FAQ discussion notes that there were three subsequent instances where entries were made without Radiation Protection controls.

A common timeframe as used in the Occupational Radiation Safety guidance in NEI 99-02, is not a fixed period of time. It is the elapsed time in which a number of events or occurrences that are associated with each other happen. The events described in this FAQ are all within a common timeframe. However, the issue demonstrated by this example is not whether the subsequent non-conformances resulting from an ongoing failure to properly control a TSLHRA are within the same (or common) timeframe. The pertinent issue in this example is whether all of the subsequent non-conformances resulted from the same cause.

In those cases where a licensee, for whatever reason (e.g., failure to survey, failure to lock the area, etc.), fails to provide adequate physical controls around a TSLHRA for an extended time, all of the subsequent non-conformances would be "concurrent non-conformances" as defined in NEI 99-02 if they were the result of the same cause. For example, an operational occurrence that created an unrecognized TSLHRA, the subsequent failure to post the area, failure to prevent unauthorized access (possible several entries), entry not controlled per an RWP, etc., are all concurrent non-conformances if they are directly attributable to the original failure to survey. However, if during the time that this TSLHRA is unidentified (or uncontrolled) there is a subsequent failure by the RP Program to take timely action that reasonably would have ended the TSHRA non-conformance (e.g., a failure to perform a routine or directed surveillance that would have identified the non-conformance, or a failure to respond to new information that indicates the potential for the unidentified or uncontrolled TSLHRA), then the subsequent non-conformances are considered a separate PI occurrence based on the failure to reasonably act and correct the condition. In such a case the non-conformances that occurred before the subsequent failure would be concurrent non-conformances (i.e., one PI occurrence) with the initial TS violation. The non-conformances following the failure to act on the new information would be concurrent with this failure to act (i.e., a separate PI occurrence). Once this new information is obtained, subsequent sharing of this new information with other staff, or validation of this new information would be concurrent with the separate PI occurrence. The NRC response to FAQ 203 is a specific example of this general staff position.

The specific example of the resin spill event at Perry referenced in this FAQ was inspected under the NRC Baseline Inspection Program. A complete description of the event is provided in PERRY INSPECTION REPORT 05000440/2012005 AND 07200069/2012002 (ML13038A702). The spill event started on the morning of June 3, 2012, when the Radwaste (RW) Operator notified the Radiation Protection (RP) staff of a potential resin spill. The inspectors identified one self-revealing green finding with three examples of the licensee's failure to perform timely radiological surveys and evaluate the potential radiological hazards. These three failures to survey were related to the following;

> <u>Failure to adequately respond to the initial notification of a possible resin spill in the Radwaste (RW) building, 574' level:</u> At approximately 0400 hours June 3, the RW operations supervisor observed a larger than expected level decrease in Condensate Backwash Settling Tank (CBST) tank inventory. The RW operations supervisor called the RP control point and informed the RP technicians that he believed there was a failed seal on the CBST transfer pump which could indicate a spill of contaminated resin. RP did not follow up to survey the area.
>
> <u>Failure to take timely action once it was recognized (or should have been recognized) that the radiological conditions in RW 574' were potentially much worse than initially assumed:</u> At approximately 1442 hours June 3, an RP technician, covering another job on the RW 574' looked down the east-west corridor hallway and observed resin outside the CBST room. Due to an incomplete shift turnover, the dayshift RP technicians, and RP supervisors, were unaware of the

reported loss of resin inventory, and possible radiological conditions of RW 574'. After leaving the area, the RP technician reported the unexpected material condition of the corridor to the on-duty RP supervisor. No subsequent surveys were performed.

Failure to take a timely survey once the decision to perform a survey was made: On Tuesday, June 5, 2012, at about 0630 hours, in response to continued concerns expressed the RP technicians about the uncharacterized radiological conditions on RW 574', the RP manager directed that a full survey of RW 574' be performed, including air samples. However, the TSLHRA remained unidentified and inadequately controlled until Thursday, June 7, when the surveys were performed at 1514 hours.

Each example represents new information or identifies organizational failures to respond in a timely manner that would have ended the on-going non-conformance to station technical specifications. Therefore, each of these three failures to take timely action and end the non-conformance with the Technical Specifications represents a separate cause of the subsequent non-conformance and therefore represents a separate reportable PI occurrence.

FAQ 12-05
Safety System Functional Failures
(Withdrawn on January 17, 2012)

Plant: Browns Ferry Nuclear Plant
Date of Event: July 11, 2012
Submittal Date: October 16, 2012
Contact: James Emens **Tel/email:** (256) 729-2636/jeemens@tva.gov
NRC Contact: Dave Dumbacher **Tel/email:** (256) 729-2573/david.dumbacher@nrc.gov

Performance Indicator: MS05, Mitigating System Functional Failures

Site-Specific FAQ (Appendix D)? No, FAQ is generic.

FAQ requested to become effective: when approved.

Question Section

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

Page 29, Lines 22-25:

> *Additional failures:* a failure leading to an evaluation in which additional failures are found is only counted as one failure; new problems found during the evaluation are not counted, even if the causes or failure modes are different. The intent is to not count additional events when problems are discovered while resolving the original problem.

Event or circumstances requiring guidance interpretation:

While reviewing design input calculations in support of the NFPA 805 transition from the 10CFR 50, Appendix R licensing basis for Browns Ferry Nuclear (BFN) plant, TVA has discovered several deficiencies related to equipment and procedures that potentially could affect the ability of the Browns Ferry plant to cope with certain postulated Appendix R fires. As examples, these deficiencies have included omissions in Safe Shutdown Instructions (SSIs), and cable routings that violated train separation requirements. These discoveries have been reported as Licensee Event Reports (LER) submitted in accordance with 10CFR 50.73(a)(2)(ii)(B), as an event or condition that resulted in the nuclear plant being in an unanalyzed condition that significantly degraded plant safety. Some of these discoveries were also reported under 10 CFR 50.73(a)(2)(v)(B), as an event or condition that could have prevented the fulfillment of a safety function. Following is a list of LERs submitted that are related to BFN Appendix R program deficiencies that were reported under 10 CFR 50.73(a)(2)(v)(A):

- LER 50-259/2010-001-00 - Units 1, 2, and 3 Appendix R Safe Shutdown Instruction Procedures Contain Incorrect Operator Manual Actions,
- LER 50-259/2012-001-00 - Unanalyzed Conditions Discovered During NFPA 805 Transition Review,
- LER 50-259/2012-002-00 - Fault Propagation During A Postulated Appendix R Event Could Result In An Inability To Close Motor Operated Valves,
- LER 50-259/2012-003-00 - Reactor Protection System Circuit Could Potentially Remain Energized During An Appendix R Fire,

- LER 50-259/2012-004-00 - Fire Damage to Cables in Fire Areas Could Cause a Residual Heat Removal Service Water Pump to Spuriously Start,
- LER 50-259/2012-007-00 - Cable Routing Error Would Result in Failure of Direct Current Control Power to Credited 4kV Shutdown Board 3EA during an Appendix R Event, and
- LER 50-259/2012-007-01 - Cable Routing Error Found in the Appendix R Separation Analysis.

For Reactor Oversight Process (ROP) Performance Indicator (PI) purposes, The Tennessee Valley Authority (TVA) counted the six discoveries in 2012 as one instance under the Safety System Functional Failure (SSFF) (MS05) PI input for 2Q2012. This decision was based on TVA's interpretation of the guidance in NEI 99-02, Section 2.2, page 29, lines 22-25. These lines indicate that when an evaluation leads to finding additional failures, the original and subsequent failures are counted as one.

The evaluation in this instance is the ongoing examination of the BFN Fire Protection program (plant equipment, procedures and design) to support the transition to NFPA-805. This examination began in 2012 and will continue until TVA submits the License Amendment Request associated with NFPA-805, currently projected for March 2013. This examination appears to align with the intent of the phrase on Lines 22-23, "…an evaluation in which additional failures are found…."

The TVA submitted a letter of intent to the NRC on March 4, 2009 for BFN to adopt NFPA 805 in accordance with 10 CFR 50.48(c). By letter dated September 17, 2009, the NRC granted a three year enforcement discretion period. By letter dated January 13, 2012, TVA informed the NRC that the schedule for submitting the license amendment request to adopt NFPA 805 had been revised to no later than March 29, 2013. By letter dated March 20, 2012, TVA requested an extension of the enforcement discretion period. By letter dated May 18, 2012, the NRC issued a Confirmatory Order to revise the date for the submittal of an acceptable license amendment request to transition BFN to March 29, 2013. In accordance with the Enforcement Policy, the enforcement discretion period would continue until the NRC issues a License Amendment.

What is the NRC resident inspector's position?

The NRC resident inspector agrees with the facts as presented, but questions whether the additional examples should be considered as "Additional failures" under the NEI 99-02 definition. The NRC has also raised the question as to when it would no longer be appropriate to count additional examples as "Additional failures" and therefore a single PI count. The inspector recommended that the FAQ process be followed for resolution.

Potentially relevant existing FAQ numbers

None.

FAQ 12-05
Safety System Functional Failures
(Withdrawn on January 17, 2012)

Response Section

Proposed Resolution of FAQ

The proposed resolution is to clarify that additional examples of SSFFs associated with a situation governed by enforcement discretion are to be considered part of the first reported instance, as described in "Additional failures."

Additionally, if it is appropriate to count the additional examples of SSFFs as "Additional failures" and a single count against the PI, is there an amount of time or a pertinent milestone after which it becomes no longer appropriate to count additional examples as "Additional failures."

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

Page 29, Lines 22-25:

Additional failures: a failure leading to an evaluation in which additional failures are found is only counted as one failure; new problems found during the evaluation are not counted, even if the causes or failure modes are different. The intent is to not count additional events when problems are discovered while resolving the original problem. **Related failures found in a situation in which enforcement discretion applies (e.g., transition to NFPA-805) are considered "Additional failures" under this definition and are therefore only counted as one failure. Once the enforcement discretion is lifted or a subsequent action to close the enforcement discretion is completed (e.g., license amendment approval, etc.), any additional examples of similar issues are no longer counted as "Additional failures" under this definition.**

Final Resolution: Withdrawn

In December 2012, TVA revised the LERs listed above to remove the previously referenced 10 CFR 50.73(a)(2)(v) criterion (safety system functional failures) since the reported conditions did not adversely impact structures, systems or components credited in the plant's safety analyses. This obviated the need for this FAQ. At the January 17, 2013 ROP public meeting, the licensee asked that this FAQ be withdrawn.

NRC Response to Withdrawn FAQ

The staff supports the withdrawal of the FAQ since events reported under 10 CFR 50.73(a)(2)(v) are used to assess reportability for the Safety System Functional Failure performance indicator.

The Performance Indicator Program as described in Inspection Manual Chapter 0608 requires that deliberations should be documented in the NRC's response to a withdrawn FAQ for knowledge-transfer purposes. The discussions are documented in the following section.

Discussions

The staff did not support the original proposed resolution from the licensee. Enforcement discretion is not within the scope of NEI 99-02. This specific enforcement discretion, as

documented in the NRC Enforcement Policy, is for a noncompliance with the requirements in 10 CFR 50.48 and Appendix R that are identified as a result of the transition to NFPA 805.

The guidance in NEI 99-02, Section 2.2, states that *a failure leading to an evaluation in which additional failures are found is only counted as one failure; new problems found during the evaluation are not counted, even if the causes or failure modes are different. The intent is to not count additional events when problems are discovered while resolving the original problem.* This guidance does not clearly apply to the conditions reported in the LERs because "a failure leading to an evaluation" did not occur. The conditions were identified during the NFPA 805 transition review, which is not considered an evaluation for the purposes of this guidance (e.g.; for determining extent of condition). If the root cause analysis for the initial SSFF included the NFPA 805 transition review as an action to identify other potential SSFFs, then the intent of Section 2.2 would be met. However, that was not the case; the NFPA 805 transition review was independent of any root cause or extent of condition evaluation for the initial SSFF(s) identified. Since the intent is not met, the licensee should report each different condition as an individual SSFF in accordance with NEI 99-02.

The staff's interpretation is that multiple SSFFs may exist because the licensee reported to the ROP Working Group that the root cause analysis (an evaluation) did not document the NFPA 805 review as an action to discover other SSFFs.

The staff believes the guidance in NEI 99-02, page 29, lines 22 - 25, that references *additional failures* should be improved to clarify what type of evaluation would be appropriate for this circumstance.