Enclosure 3

Reactor Oversight Process Task Force FAQ Log – October 23, 2013

FAQ Log for ROP Meeting October 23, 2013

FAQ No.	PI	Topic	Status	Plant/Co.	Point of Contact
13-02	IE03	Susquehanna Power Change	Introduced on 06/26/2013. Discussed 08/07/2013, 09/11/2013. TENTATIVE FINAL 09/11/2013 NRC resolution statement to be discussed 10/23/2013	Susquehanna PPL	John Tripoli (PPL) Patrick Finney (NRC)
13-03	IE03	Quad Cities Animal Intrusion	INTRODUCED 09/11/2013 To be discussed on 10/23/2013	Quad Cities Exelon	Jason Smith (Exelon) Brian Cushman (NRC)
13-04	EP03	Point Beach ANS	INTRODUCED 09/11/2013 To be discussed on 10/23/2013	Point Beach NextEra	Gerard Strharsky (NextEra) James Beavers (NRC)
13-05	IE03	Oyster Creek Downpower	INTRODUCED 09/11/2013 To be discussed on 10/23/2013	Oyster Creek Exelon	Dennis Moore (Exelon) Jeffrey Kulp (NRC)
13-06	MS07	Dresden MSPI	INTRODUCED 09/11/2013 To be discussed on 10/23/2013.	Dresden Exelon	Joshua Smith (Exelon) Chuck Phillips (NRC)
13-07	EP01	DEP Scoring Opportunity	INTRODUCED 09/11/2013 To be discussed on 10/23/2013	DCPP (Generic) PGE	Brian Ashbrook (PGE) Paul Elkmann (NRC)

NEI Contact: James E. Slider, 202-739-8015, jes@nei.org

FAQ 13-02 (Tentative NRC Response)
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.

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:

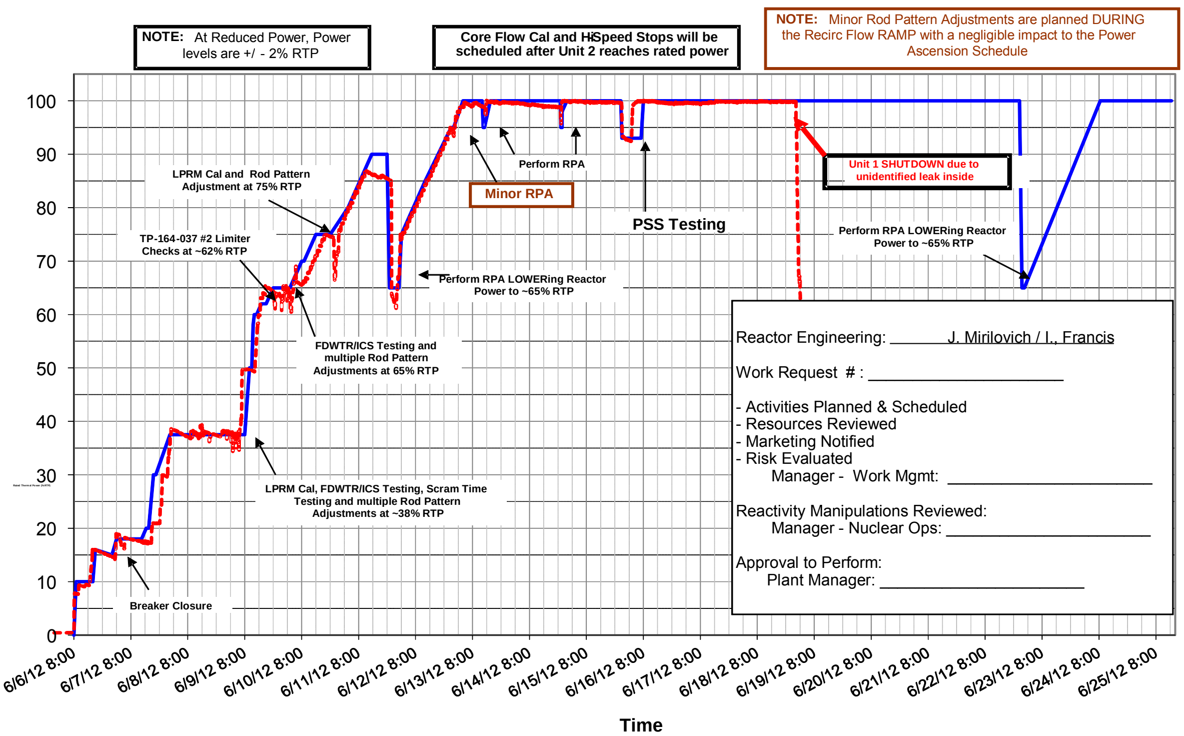
"This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator measures the number of plant power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

U1C18 BOC Startup Load Profile



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.
- The 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% beyond 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 Indicator 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.

NRC Tentative 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. If the intent cannot be agreed upon, the staff recommends removing the problematic guidance completely.

FAQ 13-03
Quad Cities Animal Intrusion

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:

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.

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

Kewaunee and Point Beach

Issue: The Kewaunee and Point Beach sites have overlapping Emergency Planning Zones (EPZ). We report siren data to the Federal Emergency Management Agency (FEMA) grouped by criterion other than entire EPZs (such as along county lines). May we report siren data for the PIs in the same fashion to eliminate confusion and prevent 'double reporting' of sirens that exist in both EPZs? Kewaunee and Point Beach share a portion of EPZs and responsibility for the sirens has been divided along the county line that runs between the two sites. FEMA has accepted this, and so far the NRC has accepted this informally.

Resolution: The purpose of the Alert and Notification System Reliability PI is to indicate the licensee's ability to maintain risk-significant EP equipment. In this unique case, each neighboring plant maintains sirens in a different county. Although the EPZ is shared, the plants do not share the same site. In this case, it is appropriate for the licensees to report the sirens they are responsible for. The NRC Web site display of information for each site will contain a footnote recognizing this shared EPZ responsibility.

FAQ requested to become effective when approved.

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.

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

Page 14
10 Equipment problems encountered during a planned power reduction greater than 20% that alone
11 may have required a power reduction of 20% or more to repair are not counted as part of this
12 indicator if they are repaired during the planned power reduction. However, if during the
13 implementation of a planned power reduction, power is reduced by more than 20% of full power
14 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:

NRC Position

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."

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

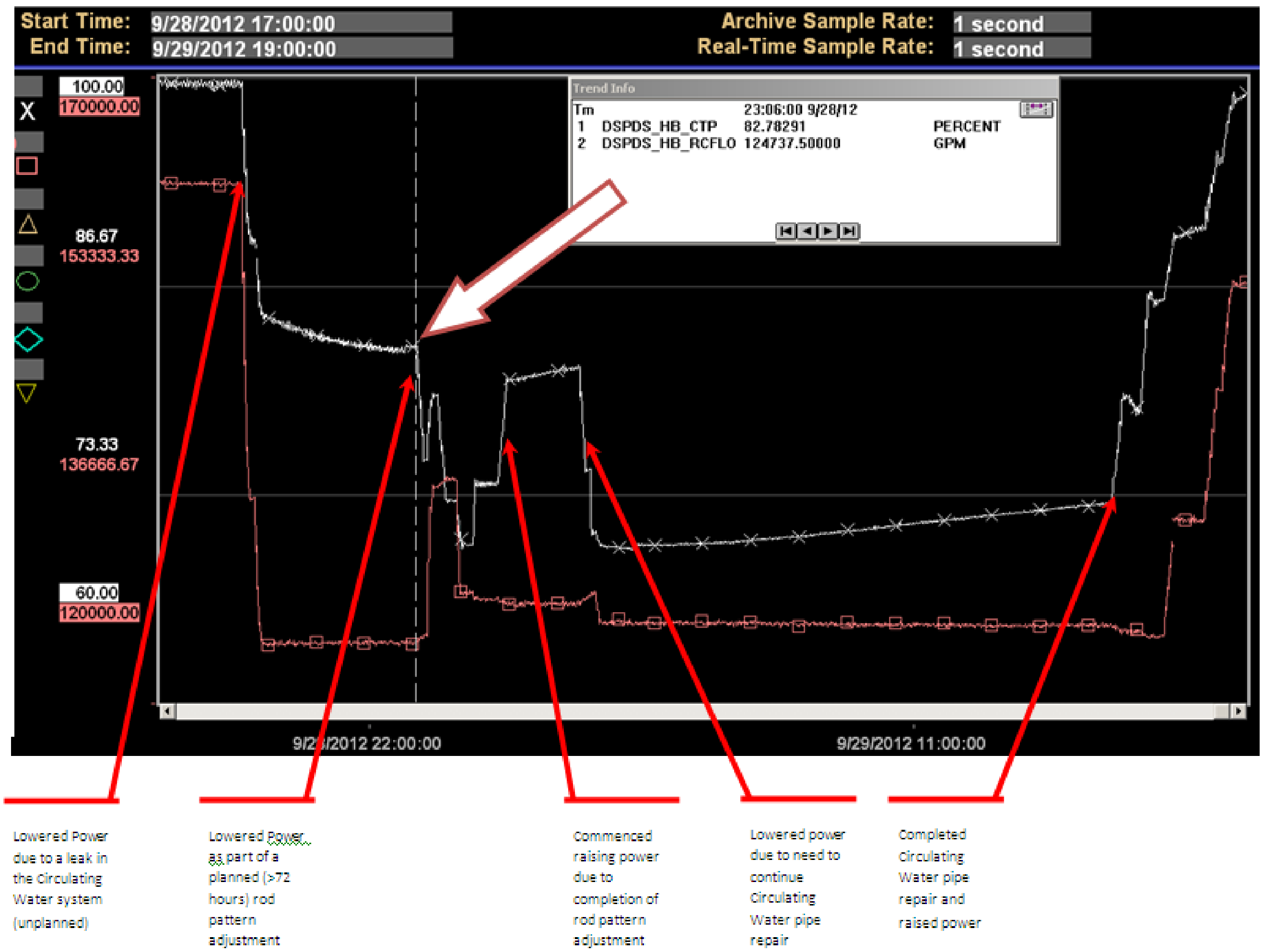
Response Section

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



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."

FAQ 13-06
Dresden MSPI

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.

FAQ 13-07
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: when approved

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 <u>not</u> 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.

<u>NRC Response</u>
TBD