Enclosure 2
Meeting Summary Handouts
of the May 4, 2011
ROP Public Meeting
Dated June 06, 2011

REACTOR OVERSIGHT PROCESS (ROP)
MONTHLY PUBLIC MEETING AGENDA

May 4, 2011; 9:00 AM – 2:00 PM; Two White Flint North Building;
Conference Room – T-10A1

9:00 – 9:05 AM	Introduction and Purpose of Meeting
9:05 – 9:15 AM	Inspection Branch Topics 1. General operating experience topics of interest 2. Opportunity for public comment
9:15 – 9:25 AM	Operating Experience Branch Topics 1. General inspection topics of interest 2. Opportunity for public comment
9:25 – 10:00 AM	Performance Assessment Branch Topics 1. General assessment topics of interest 2. New SDP Phase 2 Process using SAPHIRE 8 3. Opportunity for public comment
10:00 – 10:30 AM	Discussion of Performance Indicator (PI) Topics 1. MSPI topics 2. Opportunity for public comment
10:30 – 11:00 AM	Lunch
11:00 – 2:15 PM	Discussion of Open and New PI Frequently Asked Questions (FAQs) *Note: Topic may be moved up if meeting is ahead of schedule. The latest draft FAQs is located on the public web at: http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/draft_faqs.pdf. This list is subject to change the day before the meeting based on availability of new draft FAQs provided by the Nuclear Energy Institute. Public comments will be addressed on FAQs following the discussion.*
2:15 – 2:30 PM	Future Meeting Dates, Action Items, Future Agenda Topics

Breaks will be taken as needed

ROP Task Force Comments on April 1 Draft Revision of NRC's Inspection Manual Chapter 0608, "Performance Indicator Program"

The NRC released a proposed update to IMC-0608 on April 1, 2011. The update appears in ADAMS under accession number ML110900442. Most changes are editorial, add helpful references to SECY 99-007, or give NRC flexibility in the timing of its actions. Following is a listing of changes and comments, where appropriate.

Location in Update	Old Text	New Text	Comments
Page 2, §04.03, Line 3	All FAQs submitted to the NRC by external stakeholders…	All FAQs submitted to the ROP Working Group…	No comment to NRC. Minor change.
Page 4, §06.02.a.1, bullets	Initiating Events cornerstone includes the following indicators: Unplanned scrams per 7,000 critical hours; Scrams with loss of normal heat removal; Unplanned power changes per 7,000 critical hours	Initiating Events cornerstone includes the following indicators: Unplanned scrams per 7,000 critical hours; ~~Scrams with loss of normal heat removal;~~ Unplanned power changes per 7,000 critical hours; Unplanned Scrams with Complications	No comment to NRC. Update reflects replacement of SLNHR with USwC.
Page 5, §06.02.b	For the radiation safety area…	For the radiation safety strategic performance area…	No comment to NRC.
Page 5, §06.02.c	For the safeguards area…	For the safeguards strategic performance area…	No comment to NRC.
Page 5, §06.02.c	…the cornerstone and PIs are as follows:	…the cornerstone I is as follows:	Appears that the words "and PIs are" were meant to go where the "I" now appears.
Page 5, §06.02.c.1	Heading was "Physical Protection"	Heading is now "Security"	No comment to NRC. Change aligns with current name for the cornerstone.
Page 6, §06.02.c.1	"…overseeing the Physical Protection Cornerstone"	"…overseeing the Security Cornerstone"	No comment to NRC. Change aligns with current name for the cornerstone.
Page 6, §07.01, second paragraph	"Within five business days from receipt of the licensees' data transmissions, the NRC will post the data...Within 10 business days of receipt of the licensees' data transmittals, the NRC will place the PIs on the NRC's external web site…"	"Within three business days after the licensee's data submittal deadline (which is twenty-one days after the end of a calendar year quarter), the NRC will post the data…Within 10 business days after the licensee's data submittal deadline, the NRC will place the PIs on the NRC's external web site."	No comment to NRC. Change clarifies that NRC's target for posting the data is tied to the licensees' due date, not to the licensees' time of actual submittal.
Page 6, §07.01, second paragraph, last sentence		Adds a reference to IMC 0306, "Information Technology Support for the Reactor Oversight Process", for posting on the NRC's web site.	No comment to NRC.
Page 6, §07.02, first paragraph, sixth line		Abbreviates Inspection Manual Chapter as "IMC"	No comment to NRC.
Page 7, §08.01, first paragraph, last sentence	"Enforcement action will be taken for inaccurate PI reporting in accordance with the…"	"Enforcement action can be taken for inaccurate PI reporting…"	No comment to NRC. Appears to clarify that enforcement action is optional.
Page 8, §09, top of the page	"The process consists of the following four major components"	The process consists of the following five major components"	No comment to NRC. The change breaks the previous component "Resolution" into two pieces, one on questions not requiring a PI change and another on questions requiring a PI change.

ROP Task Force Comments on April 1 Draft Revision of NRC's Inspection Manual Chapter 0608, "Performance Indicator Program"

Location in Update	Old Text	New Text	Comments
Page 8, §09.01, second paragraph	(Describes what NRC staff should do with their questions about a PI and what the regions should do with feedback forms.)	Adds new instructions: "If the NRC staff and licensee do not agree on the NEI 99-02 guidance then a[n] FAQ should be submitted in accordance with Appendix E of NEI 99-02. However, if the licensee does not intend to submit an FAQ to NEI, then the NRC staff should submit a[n] ROP feedback form in accordance with IMC 0801 "Reactor Oversight Process Feedback Program" to solicit NRR support. The submitter should adhere to the following guidance since the feedback is in regards to an NEI document, not an internal IMC or IP for which the ROP feedback process was originally designed. 1) For the IP or IMC Number and Title block, and any additional places in the form that refer to IP or IMC, indicate "IP 711571"; 2) For the Performance Indicator Flag be sure to specify which PI requires a guidance interpretation (e.g., IE04) In the Summary and/or Comments sections state that this feedback form concerns a guidance interpretation of NEI 99-02 and include specific page numbers and lines."	No comment to NRC. Clarifies what staff should do in a situation in which the affected licensee chooses not to initiate an FAQ.
Page 9, §09.01, first full paragraph	(Describes what the Inspection Branch does with a feedback form.)	Revises the NRC's internal handling of feedback forms to be: "…If NRR agrees with the regional inspector recommendations in the feedback form, the inspector should present the licensee with the staff's consensus position and ensure that the licensee will submit a FAQ to NEI in a timely manner."	The feedback form could be submitted by any NRC staff member, not just the resident inspector as implied by this sentence. Reference Section 09.01, second paragraph. This sentence conflicts with Exhibit 1 Part 1 that shows the feedback form results going to the ROP monthly meeting. When the results of the feedback form are presented to the licensee there are three options: 1) The licensee could change the position to match the feedback form; 2) The licensee can submit a FAQ; 3) The licensee can disagree with the position and the need for a FAQ, in which case the issue should be evaluated for compliance issues.
Page 10, §09.04.a, first paragraph	"When an existing PI is ineffective, consistently generates many FAQs, or has the potential to be misleading or to create unintended consequences, there may be a need…"	"When an existing PI reveals some, or all, of the following indications there may be a need to develop a new PI: 1) Proven to be ineffective, 2) Consistently generates many FAQs, or 3) Has the potential to be misleading or to create unintended consequences"	No comment to NRC. Change appears to be cosmetic.

ROP Task Force Comments on April 1 Draft Revision of NRC's Inspection Manual Chapter 0608, "Performance Indicator Program"

Location in Update	Old Text	New Text	Comments
Page 11, §09.04.a, first full paragraph		Adds new text: "NOTE: An assessment of both the PI and inspection programs that reveals a potential safety cornerstone gap could result in the development of a new PI to ensure coverage of the key safety attribute(s). If a new PI is created to replace an existing PI, the proposed new PI should provide indication of licensee performance in the same cornerstone.	No comment to NRC. Change appears consistent with ROP Task Force position that PIs should not be evaluated in isolation.
Page 11, §09.04.a, second full paragraph	"Once the need for a new PI has been determined…the ROP Working Group will propose…"	[Same introduction as at left] "To ensure that the new PI is effective for implementation in the ROP, a number of factors should be considered. Those factors should serve as a framework for evaluating the efficacy of the proposed new PI. Specifically, a proposed new PI should: (a) Be capable of being objectively measured; (b) Allow for the establishment of a risk-informed threshold to guide NRC and licensee actions; (c) Provide a reasonable sample of performance in the area being measured; (d) Represent a valid indication of performance in the area being measured; (e) Represent a verifiable (auditable) indication of performance in the area being measured; (f) Encourage appropriate NRC and licensee actions; (g) Provide sufficient time for the NRC and licensees to correct declining performance prior to posing undue risk to public health and safety; (h) Adhere to the overall objectives of the ROP (i.e., risk-informed, objective, predictable, and understandable). NOTE: This framework includes the consideration applied for selecting the initial set of PIs that was established in SECY 99-007 and later recorded in IMC 0308, Attachment 1."	No comment to NRC. Change inserts PI criteria documented in SECY 99-007.
Page 12, §09.04.a, second paragraph	"If the proposed PI cannot identify declining performance in a timely manner, the PI must either be revised prior to proceeding or development efforts discontinued."	"If the proposed PI cannot identify declining performance in a timely manner, the PI must either be revised prior to proceeding or development efforts should be discontinued."	No comment to NRC. Change appears to give NRC flexibility in deciding whether to continue development of a new PI.
Page 13, §09.04.c, second paragraph	"Once the need for a threshold change has been identified…"	[Insert new text after "Once the need…"] "The establishment of a threshold should be consistent with the approach used in SECY 99-007, if practicable."	No comment to NRC. Change invokes a valuable reference to SECY 99-007.

ROP Task Force Comments on April 1 Draft Revision of NRC's Inspection Manual Chapter 0608, "Performance Indicator Program"

Location in Update	Old Text	New Text	Comments
Page 14, §09.05, first paragraph	[Description of closure process]	[New description replaces the old] "Once an issue has been resolved the originator of the question or feedback will receive a response in a timely manner. If the question or feedback was generated by a NRC feedback form, the lead reviewer will notify the originator of the final response in accordance with the guidance established in IMC 0801. If the question or feedback was generated by an FAQ, the ROP Working Group will adhere to the guidance in NEI 99-02, Appendix E, for documenting and posting the final resolution. If the question or feedback was generated by a public stakeholder the NRC will respond in written correspondence."	No comment to NRC. New closure process relieves NRC of previous requirement to notify originator within 14 business days after resolution is achieved. New process description also invokes NEI 99-02 for guidance on closing FAQs, appropriately.
Page 14, §09.05, second paragraph	"If a licensee disagrees with the resolution documented on a feedback form, the licensee should submit an FAQ to the ROP Working Group to present at the next ROP Working Group meeting. The FAQ process outlined in section 9.03 will be followed."	"If a licensee disagrees with the resolution documented on a feedback form, the licensee should submit an FAQ to the ROP Working Group to present at the next ROP Working Group meeting. The FAQ process discussed in sections 9.01 and 9.03 and outlined in Appendix E of NEI 99-02 will be followed."	Question for NRC: When would a licensee see the resolution documented on an NRC feedback form?
Pages 16-17	[Process diagram]	No change from previous version.	There are about 20 differences between the process shown in the process diagram and the process described in the body of IMC 0608.

For further information:

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Monitoring Unavailability of Low Risk Worth Trains/Segments

Throughout the industry, there are 100s of trains/segment were the CDE margin report shows greater than 3 years unavailability to the Green/White threshold. A sample report is provided below. For this plant, the Birnbaum value for the 2A CC pump segment is 3.7E-11. With this low a Birnbaum value, 100% unavailability of the train would increase the MSPI value 3.7E-11, more than 5 magnitudes lower than the Green/White threshold and will never result in a noticeable impact on the MSPI value. Monitoring trains/segments with this low of an impact on the index requires resources with no value added. It is therefore proposed that a Birnbaum exclusion for monitoring of trains/segments be developed, similar to what is used for excluding low risk worth valves and circuit breakers.

In order to implement a Birnbaum exclusion for trains/segments, the following actions are required:

1. Establish an appropriate Birnbaum exclusion value.
2. Determine approach to use all trains/segments in a system are below the Birnbaum exclusion value.
3. Write guidance for applying the exclusion.

CDE **MSPI Margin Report**

MSPI Indicator Margin Remaining In Green

Location **Braidwood Unit 1**
Period Ending **Mar 2011**

System ROP-MSPI-CWS MSPI Cooling Water System

Color	*MSPI*	*UAI*	*20% Deviation from UAP Baseline*	*URI*	*Risk Cap Invoked*	*PLE*
Green	-2.2E-07	3.69E-07	Yes	-5.87E-07	No	No

Maximum number of additional unavailable hours

	Unplanned UA Hrs			*Planned UA Hrs*	
Train Name	*Actual*	*Remaining in Green*	*Planned Hrs to Baseline*	*Actual*	*Remaining in Green*
CWS1 1A CC Pump Segment	4.10	12,378	0.00	36.40	12,378
CWS1 1B CC Pump Segment	0.00	12,378	12.37	3.80	12,390
CWS1 2A CC Pump Segment	4.70	857,111,303	0.00	57.80	857,111,303
CWS1 2B CC Pump Segment	0.00	857,111,303	0.00	57.20	857,111,303
CWS1 U0 CC HX Segment	0.00	1,297	0.00	186.80	1,297
CWS1 U1 CC HX Segment	0.00	994	81.98	44.90	1,076
CWS1 U2 CC HX Segment	0.00	2,739,011	157.59	91.20	2,739,169
CWS2 1A ESF Cooling Loads	0.00	71	0.00	0.00	71
CWS2 1B ESF Cooling Loads	0.00	118	0.00	0.00	118
CWS2 2A ESF Cooling Loads	0.00	6,061	159.23	0.00	6,221
CWS2 2B ESF Cooling Loads	0.00	12,276	0.00	109.80	12,276
CWS2 SX1A	62.80	932	0.00	207.40	932
CWS2 SX1B	0.00	937	0.00	305.10	937
CWS2 SX2A	46.10	32,072	0.00	449.80	32,072
CWS2 SX2B	0.10	31,124	0.00	464.30	31,124
CWS2 U1 SX033/034 Crosstie	0.00	9,316	0.00	0.00	9,316
CWS2 U2 SX033/034 Crosstie	0.00	29,164,690	99.48	109.50	29,164,789
CWS2 Unit SX005 Crosstie	0.00	1,684	0.00	190.30	1,684

ROP Task Force
Log of FAQs as of May 3, 2011

No.	PI	Topic	Status	Plant/Co.	Point of Contact
10-02 To be discussed 5/4	IE04	USwC	NRC feedback on the last mark-up was received on 1/19/11. NRC's revised mark-up of NEI 99-02 will be discussed. *[Discussed 1/20, 2/16, 3/30]*	Generic	Jim Slider (NEI) for the ROP Task Force
10-06 Not ready for discussion on 5/4	MS	Cascading Unavailability	Introduced at October 20 ROP meeting. Discussed 12/1/10. NRC to provide feedback at 1/20/11 meeting. NRC's proposed mark-up of NEI 99-02 will be discussed. *[Tentatively Approved 1/20/11; ROP TF preparing mark-up of NEI 99-02]*	Generic	Roy Linthicum (Exelon)
10-07 To be discussed 5/4	IE04	Vendor EOPs	Introduced at December 1 ROP meeting. Awaiting staff response. *[No discussion of contents 1/20, 2/16]*	Generic	Steve Vaughn (NRC)
11-01 To go FINAL on 5/4?	MS10	Cooling Water Boundary	Converted from white paper to draft FAQ. FAQ to be introduced at 1/20/11 meeting. Revised wording from ROP TF will be discussed 3/30/2011. *[Introduced and discussed 1/20, 2/16. Tentatively approved on 3/30]*	Generic	Jim Peschel (NextEra) Steve Vaughn (NRC)
11-04 To be discussed 5/4	IE03	Power Changes Needed to Recover from Loss of Equipment	Converted from white paper to draft FAQ. Introduced at 1/20/11 meeting. *[Introduced and discussed 1/20, 2/16, 3/30]*	Generic	Robin Ritzman (First Energy) Jocelyn Lian (NRC)
11-05 To be discussed 5/4	MS08	Point Beach Pumps	Introduced 1/20/2011. *[Introduced, discussed and Tentatively Approved 1/20/11; further discussed 2/16, 3/30]*	NextEra	Carol Jilek (NextEra)

No.	PI	Topic	Status	Plant/Co.	Point of Contact
11-07 To be discussed 5/4	MS	FOTP Failures	Introduced 3/30/2011	Generic	Roy Linthicum (Exelon)
11-08 (Proposed)	MS	EDG Failure Mode Definitions	To be introduced 5/4/2011	Generic	Roy Linthicum (Exelon)

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UNPLANNED SCRAMS WITH COMPLICATIONS (USWC)

Purpose

This indicator monitors that subset of unplanned automatic and manual scrams that either require additional operator actions beyond that of the “normal”[A1] scram or involve the unavailability of[A2] or inability to recover main feedwater. Such events or conditions have the potential to present additional challenges to the plant operations staff and therefore, may be more risk-significant than uncomplicated scrams.

Indicator Definition

The USwC indicator is defined as the number of unplanned scrams while critical, both manual and automatic, during the previous 4 quarters that require additional operator actions or involve the unavailability of[A3] or inability to recover main feed[A4]water as defined by the applicable flowchart (Figure 2) during the scram response (see definition of *scram response* in the Definitions of Terms section) and the associated flowchart questions.

Data Reporting Elements

The following data are required to be reported for each reactor unit.

The number of unplanned automatic and manual scrams while critical in the previous quarter that required additional operator actions~~response~~ or involved[A5] the unavailability of [A6]or inability to recover main feedwater as determined by the flowchart criteria during the scram response.

Calculation

The indicator is determined using the values reported for the previous 4 quarters as follows:

value = total unplanned scrams while critical in the previous 4 quarters that required additional operator ~~response~~ actions or involved[A7] the unavailability of[A8] or inability to recover main feedwater as defined by the applicable flowchart and the associated flowchart questions(Figure 2) during the scram response.

Definition of Terms

Scram means the shutdown of the reactor by the rapid addition of negative reactivity by any means, *e.g.*, insertion of control rods, boron, use of diverse scram switches, or opening reactor trip breakers.

Normal Scram means any scram that is not determined to be complicated in accordance with the guidance provided in the Unplanned Scrams with Complications indicator. A normal scram is synonymous with an uncomplicated scram.

Unplanned scram means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This includes scrams that occurred during the execution of procedures or evolutions in which there was a high chance of a scram occurring but the scram was neither planned nor intended.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a scram after the reactor is critical—this condition would count as a scram.

Scram Response refers to the period of time ~~which~~that[A9] starts with the onset of the initiating event and concludes when operators have completed the scram response procedures~~EOP~~[A10] ~~actions~~ and the plant has achieved a stabilized condition in accordance with approved plant procedures and as demonstrated by meeting the following criteria[A11].

For a PWR, the plant[A12] is considered "stable" when all of the following are true:

- Pressurizer pressure is within the nominal operating pressure band.
- Pressurizer level is within the no-load pressurizer band.
- L~~The l~~evel and pressure of all steam generators are~~is~~[A13] ~~between the bottom of the narrow range indication and 50%, including allowances for channel accuracies and reference leg process errors~~ within the normal operating bands[A14]. ~~and pressure is within the nominal operating pressure band.~~
- ~~The~~ RCS temperature is within the allowable RCS no-load temperature band (T_{ave} if any RCS pump running, T_{cold} if no RCS pumps running).

For a BWR, the ~~reactor~~plant[A15] is considered stable when all of the following are true:

- No emergency operating procedure (EOP) entry conditions exist related to either the primary containment or the reactor.[A16]
- Reactor cool-down rates are less than 100 degrees F/hr.
- Reactor water level is~~and pressure are~~ being maintained within the range specified by plant procedures.

Clarifying Notes

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Was Main Feedwater unavailable or not recoverable using approved plant procedures ~~following the scram~~during the scram response?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the steam generators if necessary. The qualifier of "not recoverable using approved plant procedures" will allow a licensee to answer "No" to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved emergency, normal, and off-normal operating procedures to provide the required flow to~~feed~~ the minimum number of steam generators required by the EOPs~~ to satisfy the heat sink criteria~~. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance or repair activities or non-proceduralized operating alignments require an answer of “Yes.” Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within about 30 minutes ~~post scram~~from the time it was recognized that Main Feedwater was needed. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater under certain plant conditions, and MFW is free from damage or failure ~~(*i.e.,*~~that would prevent it from~~ capable of~~[A17] performing its intended function~~)~~ and is available for use, this question should be answered as “No.”

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BWR FLOWCHART QUESTIONS (See Figure 2)

Was Main Feedwater not available or not recoverable using approved plant procedures during the scram response[A18]?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “NO” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic circuitry using plant procedures approved for use that were in place prior to the scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved emergency, normal and off-normal operating procedures. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance or repair activities or non-proceduralized operating alignments will not satisfy this question. Additionally, the restoration of Main Feedwater must be capable of being restored to provide feedwater to the reactor vessel in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within about 30 minutes from the time it was recognized that Main Feedwater was needed~~post scram~~. During startup conditions where main feedwater was not placed in service prior to the scram, this question would not be considered, and should be skipped.

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APPENDIX H

The USwC PI will monitor the following six conditions that either have the potential to complicate the operators' scram ~~recovery~~ response actions or involve the unavailability of [A19]or inability to recover main feedwater during the scram response.

1. Reactivity Control
2. Pressure Control (BWRs)/Turbine Trip (PWRs)
3. Power available to Emergency Busses
4. Need to actuate emergency injection sources
5. Availability of Main Feedwater
6. Utilization of scram recovery Emergency Operating Procedures (EOPs)

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H 1 PWR Flowchart Basis Discussion

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H 1.5 Was Main Feedwater unavailable or not recoverable using approved plant procedures ~~following the scram~~during the scram response?

This section of the indicator is a holdover from the Scrams with Loss of Normal Heat Removal indicator which the USwC indicator ~~is~~ replaced~~ing~~. Since all PWR designs have an emergency Feedwater system that operates if necessary, the availability of the normal or main Feedwater system~~,s~~ as~~is~~ a backup in emergency situations, can be important for managing risk following a reactor scram. This portion of the indicator is designed to ~~measure~~ assess that backup availability or ability to recover main feedwater as directed by approved plant procedures (e.g., the EOPs) on a loss of all emergency Feedwater.

It is not necessary for the main Feedwater system to continue operating following a reactor trip. Some plants, by design, have certain features to prevent main feedwater from continued operation or from allowing it to be restarted unless certain criteria are met. ~~The system must be free from damage or failure that would prohibit restart of the system if necessary.~~ Since some plant designs do not include electric driven main Feedwater pumps (steam driven pumps only) it may not be possible to restart main Feedwater pumps without a critical reactor. ~~Those plants should answer this question as "No" and move on. Some~~ Additionally, some other plant designs have interlocks and signals in place to prevent feeding the steam generators with main Feedwater unless reactor coolant temperature is greater than the no-load average temperature. In both cases these plants ~~should also answer this question as "No" and move on~~may be justified in answering this question as "No" if main feedwater is free from damage or failure ~~(i.e., capable of~~that can prevent it from performing its intended function~~)~~[A20] and is available for use.

Licensees should rely on the material condition availability of the equipment to reach the decision for this question. Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps and may be lower than normal if procedures allow pump operation at that lower value. As long as these support systems are able to be restarted (if not running) to support main feedwater restart within the estimated 30 minute timeframe they can be considered as available. These requirements apply until the completion or exit of the scram response. ~~procedure.~~

The availability of steam dumps to the condenser does NOT enter into this indicator at all. Use of atmospheric steam dumps following the reactor trip is acceptable for any duration.

Loss of one feed pump does not cause a loss of main feedwater. Only one is needed to remove residual heat after a trip. As long as at least one pump can still operate and provide Feedwater to the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria, main feedwater should be considered available.

The failure in a closed position of a feedwater isolation valve to a steam generator is a loss of feed to that one steam generator. As long as the main feedwater system is able to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria, the loss of ability to feed other steam generators should not be considered a loss of feedwater. Isolation of the feedwater regulating or isolation valves does not constitute a loss of feedwater if nothing prevents them from being reopened in accordance with procedures.

A Steam Generator Isolation Signal or Feedwater Isolation Signal does not constitute a loss of main feedwater as long as it can be cleared and feedwater restarted. If the isolation signal was caused by a high steam generator level, the 30-minute estimate for restart time-frame should start once the high level isolation signal has cleared.

The estimated 30-minute time-frame for restart of main Feedwater was chosen based on restarting from a hot and filled condition. Since this time frame will not be measured directly, it should be an estimation developed based on the material condition of the plant's systems following the reactor trip. If no abnormal material conditions exist, the 30 minutes should be met. If plant procedures and design would require more than 30 minutes, even if all systems were hot and the material condition of the plant's systems following the reactor trip were normal, that routine time should be used in the evaluation of this question, provided SG dry-out cannot occur on an uncomplicated trip if the time is longer than 30 minutes. The ~~opinion~~ judgment of the on-shift licensed SRO during the reactor trip should be ~~accepted~~ used in determining if this timeframe was met.

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H 3 BWR Flowchart Basis Discussion

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H 3.5 **Was Main Feedwater not available or not recoverable using approved plant procedures during the scram response?**

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “NO” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic circuitry using plant procedures approved for use that were in place prior to the scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved emergency, normal and off-normal operating procedures. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance or repair activities or non-proceduralized operating alignments will not satisfy this question. Additionally, the restoration of Main Feedwater must be capable of being restored to provide feedwater to the reactor vessel in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within about 30 minutes from the time it was recognized that Main Feedwater was needed~~post scram~~. During startup conditions where Main Feedwater was not placed in service prior to the scram, this question would not be considered, and should be skipped.

H 3.6 Following initial transient, did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOPs?

Since BWR designs have an emergency high pressure system that operates automatically between a vessel-high and vessel-low level, it is not necessary for the Main Feedwater System to continue operating following a reactor trip. However, failure of the Main Feedwater System to be available is considered to be risk significant enough to require a “Yes” response for this PI. To be considered available, the system must be free from damage or failure that would prohibit restart of the system. Therefore, there is some reliance on the material condition or availability of the equipment to reach the decision for this question. Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps~~,~~ and may be lower than normal if procedures allow pump operation at that lower value.

The estimated 30 minute time-frame for restart of Main Feedwater was chosen based on restarting from a hot condition with adequate reactor water level. Since this time-frame will not be measured directly, it should be an estimation developed based on the material condition of the plants systems following the reactor trip. If no abnormal material conditions exist, the 30 minutes should be capable of being met. If plant procedures and design would require more than 30 minutes, even if all systems were hot and the material condition of the systems following the reactor trip were normal, a routine time should be used in the evaluation of this question. The ~~considered opinion~~ judgment of an on-shift licensed SRO should be used in determining if ~~in meeting~~ this time-frame is met~~acceptable~~.

When a scram occurs plant operators will enter the EOPs to respond to the condition. In the case of a routine scram the procedure entered will be exited fairly rapidly after verifying that the reactor is shutdown, excessive cooling is not in progress, electric power is available, and reactor coolant pressures and temperatures are at expected values and controlled. Once these verifications are done and the plant conditions considered "stable" (see guidance in the Definition of Terms section under *scram response*) operators will exit the initial procedure to another procedure that will stabilize and prepare the remainder of the plant for transition for the use of normal operating procedures. The plant would then be ready be maintained in Hot Standby, to perform a controlled normal cool down, or to begin the restart process. The criteria in this question is used to verify that there were no other conditions that developed during the stabilization of the plant in the scram response related vessel parameters that required continued operation in the EOPs or re-entry into the EOPs or transition to a follow-on EOP. Maintaining operation in EOPs that are not related to vessel and drywell parameters do not count in this PI.

For example:

Suppression Pool level high or low require entry into an EOP on Containment Control. Meeting EOP entry conditions for this EOP do not count in this PI.

FAQ 10-07, Vendor Differences in EOPs

Plant: Generic

Date of Event: N/A

Submittal Date: 12/1/2010

Licensee Contact: Jim Slider Tel/email: 202.739.8015/jes@nei.org

NRC Contact: Steve Vaughn Tel/email: 301.415.3640/Stephen.Vaughn@nrc.gov

Performance Indicator: USwC – IE04

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 21, lines 5-13; Page 23, line 15-23; H-5, line 39-46; H-6, lines 1-12; H-20, lines 21-46; H-21, line 1-11;

Event or circumstances requiring guidance interpretation:

As stated in FAQ 10-05 (ID #475), Palo Verde proposed additional wording to Appendix D of NEI 99-02 that would relieve Combustion Engineering (CE) plants from reporting a complicated scram for loss of forced cooling (LOFC) events as long as the LOFC event was not caused by a loss of off-site power (LOOP). The guidance in NEI 99-02 was clear and did not result in a question of interpretation; rather, the licensee sought relief from the reporting guidance. The NRC determined that the LOFC at Palo Verde counted as a complicated scram because more than one EOP was entered while the operators responded to the event. However, representatives from Palo Verde expressed concern that Westinghouse plants were at an unfair advantage because the structure of their EOPs would lead to a different determination under the PI guidance for the same scram. For example, a scram at a Westinghouse plant might result in only one EOP entry, while the same scram at a CE plant might result in entering multiple EOPs. The ROP Working Group agreed to initiate a generic FAQ to evaluate the potential disparity among vendor designs and recommend changes to "level the playing field."

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

N/A

Potentially relevant existing FAQ numbers

FAQ 10-05 (ID #475)

Response Section

Proposed Resolution of FAQ: Revise the guidance to ensure that a similar scram experienced at different vendor sites will result in consistent implementation.

Proposed Changes to NEI 99-02

Page 21, lines 5-13:

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as “No”. Approved exceptions to this requirement include: 1) the discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff, 2) use of the Re-diagnosis Procedure by Operations unless a transition to another EOP is required, and 3) **entry into another EOP** when securing forced circulation if maintenance of natural circulation is addressed in the separate EOP.

Page H-6, lines 5-12:

There are some EOPs that are used specifically at the operator discretion and are not required to be used. In the Westinghouse EOP suite these are Yellow Path functional restoration procedures and the re-diagnosis procedures. These procedures typically verify that the operator is taking the correct action (re-diagnosis) or the stabilization of some minor plant parameters (Yellow path). Use of these procedures is an allowed exception to this step.

In addition, the scope of the Westinghouse normal scram response procedure (ES01) encompasses loss of forced circulation events, whereas other PWR EOP schemes may require entry into a separate EOP. Loss of forced circulation events, in themselves, do not result in complications for the operator nor are they risk-significant unless required in response to an event such as Loss of Offsite Power. Therefore, in order to treat events of similar type consistently, entry into an additional EOP specific to a loss of forced circulation event is likewise an allowed exception to this step. Maintenance of the plant in Mode 3 on natural circulation requires monitoring of temperatures that are already monitored. This does not involve additional challenges to plant safety functions or the control staff. If the EOP scheme has the control room operator exit the normal scram procedure for a Loss of Forced Circulation and the EOP was exited upon restoration of forced circulation without commencing a plant cool down, then the use of an additional EOP to address the Loss of Forced Circulation shall not require counting under this criterion. If the EOP was used in response to an event such as a Loss of Off-site Power, this exception cannot be used.

Other than the above described exceptions, transition out of these procedures to an EOP different from the current procedure in effect, i.e. a new procedure or the base procedure, would count as a complication.

FAQ TEMPLATE
FAQ 11-01: Cooling Water Boundary (Generic)
Updated 3/7/2011

Plant:	Generic
Date of Event:	NA
Submittal Date:	01/20/11
Licensee Contact:	Jim Peschel, Tel/email: 603.773.7194/james_peschel@nexteraenergy.com
NRC Contact:	Steve Vaughn, Tel/email: 301.415.3640/stephen.vaughn@nrc.gov

Performance Indicator: MS-10, Mitigating System Performance Index (Cooling Water Systems)

Site Specific FAQ (Appendix D)? No

FAQ requested to become effective: October 1, 2011

Question Section

NEI 99-02, Rev. 6, provides guidance for the cooling water system scope on pages F-52 and F-53. The text from page F-53, lines 2 through 7, highlighted in italics below, indicates that only the last valve in a cooling water system line is included in the boundary of the monitored component. While this may be correct in most applications, there are plant configurations where a cooling water system line running to a monitored system (EDG for example) has more than one isolation valve (e.g., manual isolation valve(s)). If the isolation valve(s) were closed it would only result in supported train unavailability and would not affect the availability of the cooling water system. However, the guidance on page F-53, lines 2 through 7, could lead one to the opposite conclusion and suggest that the cooling water system would be unavailable.

NEI 99-02, Rev. 6, Page F-53, lines 1 through 9:

> Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. *Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to the other monitored systems are included in the system scope up to, but not including, the last valve that connects the cooling water support system to components in a single monitored system. This last valve is included in the other monitored system boundary. If the last valve provides cooling to SSCs in more than one monitored system, then it is included in the cooling water support system.* Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

Question - Should a cooling water system isolation valve(s) in a line supplying a single monitored component be included in the monitored train's system boundary?

The industry and the NRC agree on the issue and question as described above.

Response Section

Response – Yes, a cooling water system isolation valve(s) in a line supplying a single monitored train should be included in the monitored train's system boundary.

Revise NEI 99-02, Rev. 6, Page F-53, lines 1 through 9, to read as follows:

> Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are

necessary to provide cooling to the other monitored ~~systems~~ trains or segments are included in the cooling water system scope up to, but not including, the ~~last~~ isolation valve(s) that connect(s) the cooling water support system to components in a single monitored ~~system~~ train or segment. This/~~these~~ ~~last~~ isolation valve is/~~are~~ included in the ~~other~~ monitored ~~system~~ train or segment boundary. ~~If the~~The last valve(s) that provides cooling to SSCs in more than one monitored ~~system or train~~train or segment~~, then it~~ is included in the cooling water support system. ~~If the cooling water line to a single monitored component or train contains components~~All valves (e.g., manual isolation valves or motor operated valves (MOVs))~~ that would only affect the monitored component or train, those components~~ in a cooling water line to a single monitored train or segment -are included in the ~~-other system~~monitored train or segment boundary. Figure F-~~1~~-6 depicts the treatment of multiple isolation valves. Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

###

Cooling Water System Boundary

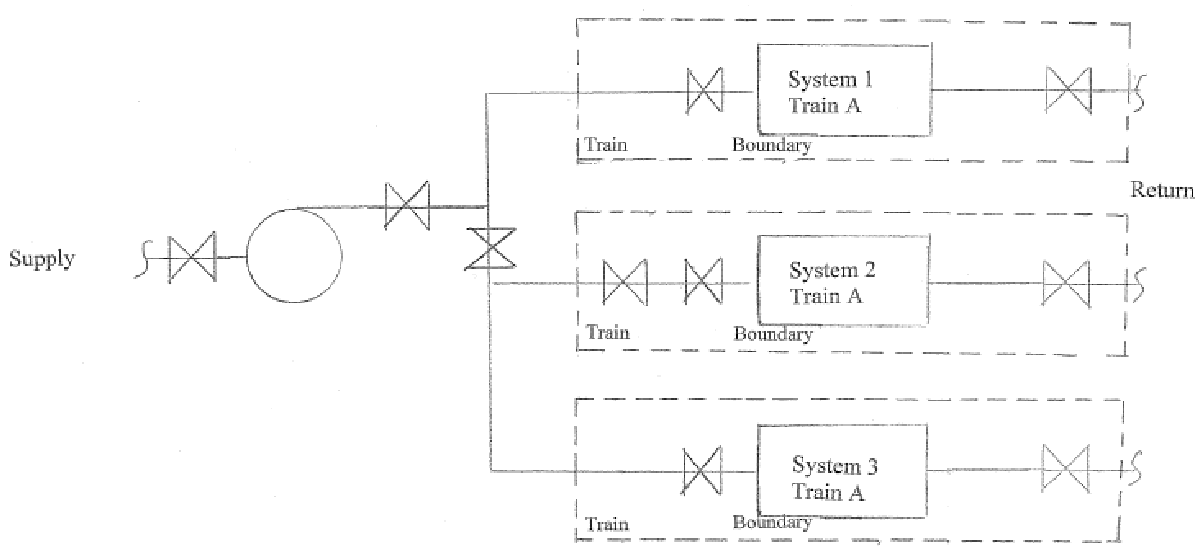


Figure F-6

FAQ 11-04, Power Changes to Recover Lost Equipment

Plant: Generic

Date of Event: June 4, 2010

Submittal Date: January 20, 2011

Contact: Robin Ritzman **Tel/email:** 330-384-5414 rritzman@firstenergycorp.com

NRC Contact: Jocelyn Lian **Tel/email:** 301-415-4666 Jocelyn.Lian@nrc.gov

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

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, Lines 24 – 29

Event or circumstances requiring guidance interpretation:

At 0707 hours on June 4, 2010, the Perry Plant entered single loop operation (SLO) when reactor recirculation pump A tripped OFF due to a failed optical isolator card. Reactor power in SLO was approximately 58% RTP. This power change is counted as an unplanned power change under the PI because the power change was greater than 20% (100% to 58%) and was initiated less than 72 hours following discovery of the off-normal condition.

After replacing the optical isolator card, it was necessary to reduce power to approximately 21% to establish reactor conditions necessary to restart reactor recirculation pump A and commence power ascension. The power reduction began at 2220 hours and ended at 1827 hours on June 5, 2010. The second power reduction was also counted as an unplanned power change under the PI because the power change was greater than 20% (58% to 21%) and was initiated less than 72 hours following discovery of the off-normal condition.

The question being asked in this case is whether the second power reduction should be counted as a separate occurrence. Clearly, the second power reduction was implemented to address the initial condition (i.e., reactor recirculation pump A trip). It is not desirable for a boiling water reactor (BWR) to operate in SLO for long periods of time, although SLO is a licensed operating mode. The reactor has to be brought a condition with adequate margins to thermal limits and stability in order to re-start the non-operating recirculation pump after repairs are completed. A power reduction is necessary to reach those conditions. The operating recirculation pump has to be transferred to slow speed. Then, the non-operating pump is started in slow speed at the desired power level. Power ascension may commence with both pumps running in slow speed.

The indicator monitors the number of unplanned power changes that could have, under other plant conditions, challenged safety functions. Operating in SLO in accordance with Technical Specifications does not challenge nuclear safety or is in itself, risk-significant. Therefore, a second power reduction to recover a non-operating recirculation pump does not appear to be within the intent of the PI.

The guidance on NEI 99-02 page 14 lines 23 through 30 and beginning on line 42 indicates that power changes resulting from proper implementation of preexisting procedural guidance which are not in response to an equipment failure or personnel error are not meant to be counted by this indicator. This is in direct contrast to power changes resulting from equipment failures or personnel errors. Consistent with this guidance, voluntary power changes (i.e., the timing of the power change was at the discretion of plant management and not a result of degrading conditions) to restore equipment to service in accordance with ~~previously existing~~approved procedures does not contribute to this indicator either by adding to the magnitude of the initiating event unplanned power change or being counted separately.

Guidance in NEI 99-02 is requested to clarify reporting criteria for situations similar to the Perry event, where a power reduction is required to place equipment in service, such as to recover a non-operating reactor recirculation pump. No clarification is needed for the initial trip to enter SLO which will be counted and reported under the PI.

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

The NRC resident inspector agrees with the facts as stated in the FAQ. In the Perry case that initiated this FAQ, both unplanned power changes were reported. The NRC inspector believes that NEI 99-02, as written, requires two unplanned power changes to be reported.

Potentially relevant existing FAQ numbers

None identified.

Response Section

Proposed Resolution of FAQ

Power changes implemented less than 72 hours from time of discovery, in accordance with ~~preexisting~~ approved procedures, for the purpose of placing equipment in service, such as restarting a non-operating reactor recirculation pump in a BWR plant or a heater drain pump, should not be reported under this PI. The initiating event or condition that resulted in the need to restore the equipment is the event evaluated under this criterion.

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

Add to Clarifying Notes for Unplanned Power Changes per 7,000 Critical Hours in NEI 99-02, page 14:

Current Guidance:

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.

Add the following to the end of the sentence on line 17:

> ~~Voluntary p~~Power changes ~~(i.e., the timing of the power change was at the discretion of plant management and not a result of degrading conditions)~~ to restore equipment to service in accordance with ~~previously existing~~approved procedures do~~es~~ not contribute to this indicator either by adding to the magnitude of an initiating event unplanned power change or being counted separately. This does not include downpowers that are conducted to perform corrective maintenance.

Current Guidance:

Unplanned power changes include 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).

Add the following to the end of line 30:

Alternately, if the power change is implemented to restore equipment to service and is performed using ~~a previously existing~~an approved procedure, the power change(s) (increases or decreases) to restore the equipment to service would not count against this indicator.

[Text was revised 4/12/11 in response to feedback from Jocelyn Lian after the March 30 meeting. ROP TF revised Lian mark-up on 5/3/11.]

FAQ 11-05: Point Beach Unit 1 and Unit 2 Auxiliary Feedwater (AF) Systems

Plant:	Point Beach Units 1 and 2
Date of Event:	NA
Submittal Date:	January 20, 2011
Licensee Contact:	Carol Jilek, 920-755-7345, carol.jilek@nexteraenergy.com
NRC Contact:	NA

Performance Indicator: MS-08, Heat Removal Systems

Site Specific FAQ (Appendix D)? YES

FAQ requested to become effective upon Point Beach implementation of the new technical specification for the Auxiliary Feedwater (AF) Systems in the second quarter of 2011.

The purposes of this FAQ are: (1) to request a one-time exemption from the reporting guidance of NEI 99-02, (2) to request approval for how unavailability and unreliability data will be characterized and reported, and (3) to request approval to revise NEI 99-02, Revision 6, Appendix F, Table 7. This FAQ was submitted because of plant-specific circumstances at Point Beach involving major design changes to the Unit 1 and Unit 2 Auxiliary Feedwater systems that are scheduled to be implemented during the second quarter of 2011. Reference NEI 99-02, Revision 6, Appendix E, page E-1, lines 18 and 19.

Question Section

NEI 99-02 guidance needing interpretation (include page and line criterion):

Point Beach is requesting a one-time exemption from the PI reporting guidance. Specifically, Point Beach wants to know if it is acceptable to gray out MS08, Heat Removal Systems, for the second quarter of 2011 as the results will not be representative of the current PRA and MSPI Document for the quarter.

Point Beach is requesting approval to characterize MS08 data as follows:

- As the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, is it acceptable to determine the baseline unavailability data (nominally 2002-2004) for the new trains/segments by utilizing the baseline unavailability data for the existing trains/segments, removing the unavailability taken when the other unit was in an outage and averaging the data over three years?
- As the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, is it acceptable to determine the past three years historical

unavailability for the new trains/segments by utilizing the data for the existing trains/segments removing the unavailability taken when the other unit was in an outage and averaging the data over three years?

- Is it acceptable to update the device records in CDE at the time the new pumps and associated monitored valves are placed in service and to update the train definition in the MSPI Basis Document at the end of the second quarter of 2011?

Finally, Point Beach wants to know if it is acceptable to revise the generic common cause failure adjustment value in NEI 99-02, Appendix F, Table 7, from 1.25 to 1.0 per this FAQ and to update NEI 99-02 at a later date after the systems are placed in service.

Event or circumstances requiring guidance interpretation:

Point Beach is upgrading the Unit 1 and Unit 2 auxiliary feedwater systems (AF) during the second quarter of 2011 with Unit 2 being completed during the spring outage and Unit 1 while the plant is on line. The current AF design has two motor-driven AF pumps that are shared between the two units. In the current configuration, the operating unit has planned unavailability during the other unit's refueling outage. After the upgrade modifications are completed, the AF system will have one new motor-driven pump dedicated to each unit and will no longer have planned unavailability during the other unit's refueling outage. The new pumps will be the same model casing as the old pumps, but will have a different impeller, resulting in a higher flow rate, and will be powered by 4160V versus 480V. The preventive maintenance activities for the new pumps and associated monitored valves will be essentially the same as those for the existing pumps and associated monitored valves. The change will reduce the number of motor-driven AF trains from two to one per unit and will change the Point Beach generic common cause failure adjustment value from 1.25 to 1.0 in NEI 99-02, Appendix F, Table 7.

The refueling outage is scheduled to be completed during the second quarter of 2011. As the units will be putting the new AF pumps and associated monitored valves in service during the middle of a quarter, the device records in CDE will be updated upon entry into MODE 4 ascending for Unit 2 and when the new AF pump and associated monitored valves are placed in service for Unit 1. However, CDE and the MSPI Basis Document will not be updated until the end of the second quarter to reflect the new PRA and the new train definitions.

The completion of the modification during the middle of a quarter will result in the inability to implement all of the guidance in NEI 99-02 related to reporting of data in CDE. The goal is to provide a second quarter MSPI submittal for AF that accurately reflects the actual availability and reliability of the existing and new AF system configurations and implements the guidance of NEI 99-02 as much as reasonable. However, as CDE does not support the submittal of split data and does not allow PRA model changes mid-quarter, an MSPI result for MS08, Heat Removal Systems, reflecting second quarter 2011 AF system unavailability and reliability would not be representative of the new system and would not provide meaningful results. Therefore, the exemptions above from NEI 99-02 guidance are requested for Point Beach based upon the system design changes being implemented in the second quarter of 2011.

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

The licensee and the NRC agree on the facts.

Potentially relevant existing FAQ numbers:

None

Resolution

Point Beach may have a one-time exemption from the reporting guidance on Page 2, Lines 15-23, of NEI 99-02, Revision 6. The 2Q2011 MS08 PI will be characterized as "Insufficient Data to Calculate PI," as indicated by:

I

on the NRC's "ROP Performance Indicators Summary" Web site because (1) the results will not be representative of the current PRA and MSPI Basis Document for that quarter and (2) the data reflecting the actual plant configuration cannot be processed in CDE software. A comment shall be added to the CDE submittal file explaining the basis for this characterization, which will include that the modification was installed mid-quarter, CDE is not capable of processing a "data split" within the same quarter, CDE does not allow mid-quarter PRA model changes, and an MSPI result for MS08, Heat Removal Systems, reflecting 2Q2011 AF system unavailability and reliability would not be representative of the new system nor provide meaningful results.

~~[ROP task force needs to clarify whether numerical data will be provided to NRC and how it will be processed for 2Q2011 & subsequent quarters. Although the indicator will be denoted as "I" on the PI chart Web site, the other websites showing the actual numerical values & thresholds (http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/POIN1/poin1_pi.html#MS08 and http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/POIN2/poin2_pi.html#MS08)~~

~~will need more explanation.]~~ AF unavailability and reliability data will ~~[not?]~~ be reported to the NRC for 2Q2011. The data will ~~[not?]~~ be used for assessing MS08 data for subsequent quarters.

Because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the baseline unavailability data (nominally 2002-2004) for the new trains by using the unavailability data for the existing trains, removing the unavailability that was reported when the other unit was in an outage, and averaging the data over three years. With respect to historical unavailability data, because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the past three years of historical unavailability for the new trains by using the data for the existing trains, removing the unavailability taken when the other unit was in an outage, and averaging the data over three years. Point Beach will also update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on system and train boundaries.

With respect to reliability data, Point Beach will update the device records and associated reliability data in CDE at the time the new pumps and associated monitored valves are placed in service and will update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on monitored component boundaries. The most recent three years of reliability data for the currently installed pumps will serve as the reliability data for the new pumps because of their similar design and function~~. Reliability data will be collected when the modification is installed.~~

It is acceptable to revise the HRS/MDP Standby generic common cause failure adjustment value from 1.25 to 1.00, which will take effect upon the implementation of the modification, in NEI 99-02, Revision 6, Appendix F, Table 7. .

The following text will be added to Page D-5, Appendix D to NEI 99-02, starting at Line ~~42~~20:

Issue: Point Beach is upgrading the Unit 1 and Unit 2 auxiliary feedwater systems (AF) during the second quarter of 2011 with Unit 2 being completed during the spring outage and Unit 1 while the plant is on line. The current AF design has two motor-driven AF pumps that are shared between the two units. In the current configuration, the operating unit has planned unavailability during the other unit's refueling outage. After the upgrade modifications are completed, the AF system will have one new motor-driven pump dedicated to each unit and will no longer have planned unavailability during the other unit's refueling outage. The new pumps will be the same model casing as the old pumps, but will have a different impeller, resulting in a higher flow rate, and will be powered by 4160V versus 480V. The preventive maintenance activities for the new pumps and associated monitored valves will be essentially the same as those for the existing pumps and associated monitored valves. The change will reduce the number of motor-driven AF trains from two to one per unit and will change the Point Beach generic common cause failure adjustment value from 1.25 to 1.0 in NEI 99-02, Appendix F, Table 7.

The refueling outage is scheduled to be completed during the second quarter of 2011. As the units will be putting the new AF pumps and associated monitored valves in service during the middle of a quarter, the device records in CDE will be updated upon entry into MODE 4 ascending for Unit 2 and when the new AF pump and associated monitored valves are placed in service for Unit 1. However, CDE and the MSPI Basis Document will not be updated until the end of the second quarter to reflect the new PRA and the new train definitions.

The completion of the modification during the middle of a quarter will result in the inability to implement all of the guidance in NEI 99-02 related to reporting of data in CDE. The goal is to provide a second quarter MSPI submittal for AF that accurately reflects the actual availability and reliability of the existing and new AF system configurations and implements the guidance of NEI 99-02 as much as reasonable. However, as CDE does not support the submittal of split data and does not allow PRA model changes mid-quarter, an MSPI result for MS08, Heat Removal Systems, reflecting second quarter 2011 AF system unavailability and reliability would not be representative of the new system and would not provide meaningful results.

Therefore, exemptions from NEI 99-02 reporting guidance are requested for Point Beach based upon the system design changes being implemented in the second quarter of 2011.

Resolution:

Point Beach may have a one-time exemption from the reporting guidance on Page 2, Lines 15-23, of NEI 99-02, Revision 6. The 2Q2011 MS08 PI will be characterized as "Insufficient Data to Calculate PI," as indicated by:

I

on the NRC's "ROP Performance Indicators Summary" Web site because (1) the results will not be representative of the current PRA and MSPI Basis Document for that quarter and (2) the data reflecting the actual plant configuration cannot be processed in CDE software. A comment shall be added to the CDE submittal file explaining the basis for this characterization, which will include that the modification was installed mid-quarter, CDE is not capable of processing a "data split" within the same quarter, CDE does not allow mid-quarter PRA model changes, and an MSPI result for MS08, Heat Removal Systems, reflecting 2Q2011 AF system unavailability and reliability would not be representative of the new system nor provide meaningful results.

AF unavailability and reliability data will be reported to the NRC for 2Q2011. The data will be used for assessing MS08 data for subsequent quarters.

Because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the baseline unavailability data (nominally 2002-2004) for the new trains by using the unavailability data for the existing trains, removing the unavailability that was reported when the other unit was in an outage, and averaging the data over three years. With respect to historical unavailability data, because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the past three years of historical unavailability for the new trains by using the data for the existing trains, removing the unavailability taken when the other unit was in an outage, and averaging the data over three years. Point Beach will also update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on system and train boundaries.

With respect to reliability data, Point Beach will update the device records and associated reliability data in CDE at the time the new pumps and associated monitored valves are placed in service and will update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on monitored component boundaries. The most recent three years of reliability data for the currently installed pumps will serve as the reliability data for the new pumps because of their similar design and function

It is acceptable to revise the HRS/MDP Standby generic common cause failure adjustment value from 1.25 to 1.00, which will take effect upon the implementation of the modification, in NEI 99-02, Revision 6, Appendix F, Table 7. .

The following text will be added to Page D-5, Appendix D to NEI 99-02, starting at Line 20:

~~[Use final resolution text from above.]~~

FAQ 11-07, FOTP Failures

Plant: **Generic**

Date of Event: **N/A**

Submittal Date: **3/30/11**

Licensee Contact: **Roy Linthicum, 630-657-3846, roy.linthicum@exeloncorp.com**

NRC Contact: **Steve Vaughn**

Performance Indicator: **Mitigating Systems**

Site Specific FAQ: **No**

FAQ requested to become effective: October 1, 2011

Question Section:

NEI 99-02 section F.5 page F-45 provides inconsistent treatment of EDG Fuel Oil Transfer pumps (FOTPs). The FOTPs are identified as being within the system boundary but are not monitored components nor do they contribute to the unavailability unless there is only one pump per EDG. As noted in the guidance, the reason for this treatment is that the FOTP contribution to MSPI was expected to be small. Additional investigation has shown that for some plant configurations, the contribution from the FOTPs could be significant, based on plant design details such as number of pumps, number of EDGs, Day Tank Capacity, cross connect capability, etc. Therefore, appropriate consideration of the FOTPs in MSPI is needed.

Several options for adding the FOTPs to MSPI were investigated, including added the pumps as separate monitored components or considering them within the boundary of the EDG super-component. Based on limitations of the current Consolidated Data Entry software design, it was determined that inclusion of the FOTPs as being with the EDG super-component boundary is the most cost effective option available.

Guidance needing clarification/interpretation:

Revise NEI 99-02 section F.5 and Figure F-1 to include the Fuel Oil Transfer Pumps within the EDG super-component boundary.

Event requiring guidance interpretation:

N/A. This FAQ is for general guidance improvement and does not address a specific event.

NRC Resident Inspector Position:

The NRC is in agreement with the need to revise guidance on the treatment of Fuel Oil Transfer Pumps.

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

NA.

Potentially relevant existing FAQ numbers: NA

Response Section:

Proposed Resolution of FAQ:

It is recommended that the following proposed wording changes or changes with equivalent meaning be incorporated into NEI 99-02.

Licensee proposed wording changes:

<u>Bolded and underlined phrases indicate proposed changes</u>, strike-throughs indicate deletions.

Page F-19, Table 2

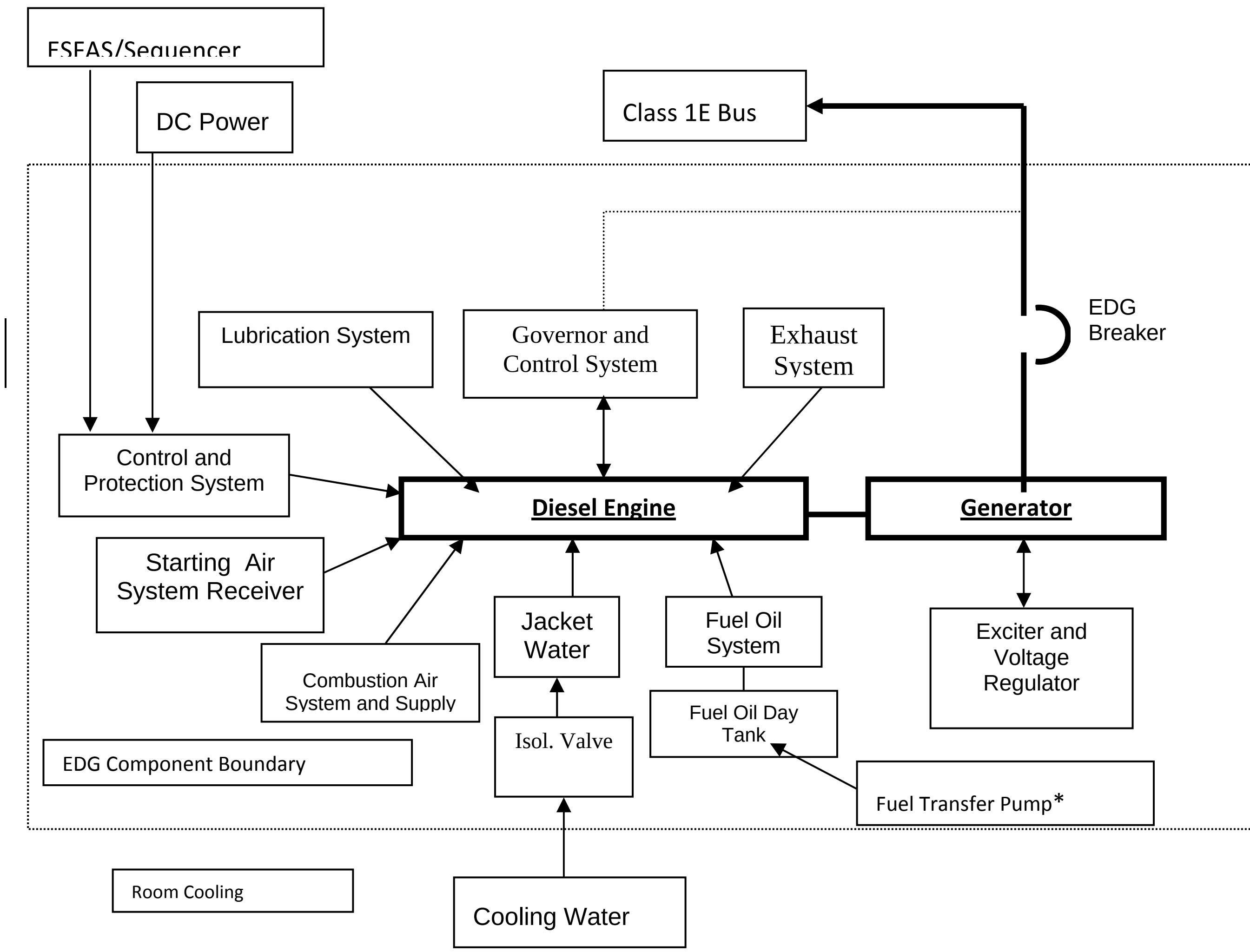
The diesel generator boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local), ***fuel oil transfer pumps***, cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, cooling water isolation valves, circuit breaker for supply to safeguard buses and their associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components

Page F-45: Line 33 – Page F-46 Line 2

The EDG component boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local or day tank ***and fuel oil transfer pumps***), cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, cooling water isolation valves, circuit breaker for supply to safeguard buses and their associated control circuit. Air compressors are not part of the EDG component boundary.

The fuel transfer pumps required to meet the PRA mission time are within the ***EDG component*** ~~system~~ boundary, but are not considered to be a ***separate*** monitored component for reliability monitoring in the EDG system. Additionally they are monitored for contribution to train unavailability ~~only~~ if ***the fuel oil transfer pump(s) is (are) required to meet the EDG mission time.***~~an EDG train can only be supplied from a single transfer pump. Where the capability exists to supply an EDG from redundant transfer pumps, the contribution to the EDG MSPI from these components is expected to be small compared to the contribution from the EDG itself. Monitoring the transfer pumps for reliability is not practical because accurate estimations of demands and run hours are not feasible (due to the auto start and stop feature of the pump) considering the expected small contribution to the index.~~

Page F-55, Figure F-1



- The Fuel Transfer Pump is included in the EDG ***Component*** ~~System~~ Boundary. See Section 5 for monitoring requirements.

FAQ 11-08, EDG Failure Mode Definitions

Plant: Generic

Date of Event: NA

Submittal Date: March 30, 2011

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NRC Contact: ______________________ Tel/email: ________________

Performance Indicator: MS06

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective on 10/01/2011.

Question Section

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

The Guidance in question begins on page F-25 line 21 and ends on F-26 line 9.

Event or circumstances requiring guidance interpretation:

There is no event driving this requested change to the guidance. The existing definitions for EDG Failure to Start, Load/Run, and Run are confusing and somewhat contradictory. Industry is proposing to change the guidance as described below. In addition, the failure definitions are being changed to address inclusion of the EDG Fuel Oil Transfer Pumps as being within the scope of the EDG super component boundary.

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

NA

Potentially relevant existing FAQ numbers

NA

Response Section

Proposed Resolution of FAQ

Make the changes to the guidance described below.

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

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

(Proposed) *EDG failure to start:* A failure to start includes those failures up to the point where the EDG output breaker has received a signal to close. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.) See the EDG failure to run definition for treatment of Fuel Oil Transfer Pump failures.

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

(Proposed) *EDG failure to load/run:* Failure of an EDG, given that it has successfully started, a failure of the EDG output breaker to close, or a failure to run/operate for one hour during surveillance test load sequencing or actual demand is considered a failure to load/run. The one hour clock starts at the time that the EDG output breaker closes. During surveillance testing the EDG may not be fully loaded. Failure to load/run also includes failures of the EDG output breaker to re-close following a grid disturbance if the EDG was running paralleled to the grid. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed). See the EDG failure to run definition for treatment of Fuel Oil Transfer Pump failures.

(Existing) *EDG failure to run:* Given that it has successfully started and loaded and run for an hour, a failure of an EDG to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

(Proposed*) EDG failure to run:* Failure of an EDG, given that it has successfully started, the output breaker successfully closed, and the EDG has run for an hour after the output breaker closed, is considered a failure to run/operate. During surveillance testing the EDG may not be fully loaded. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.) Failures of the EDG Fuel Oil Transfer Pump(s) are considered to be EDG failures to run if the failure of the EDG Fuel Oil Transfer Pump results in failure of the EDG to be able to run for 24 hours. This applies even in those circumstances where the failure determination would be either failure to start or failure to load/run. In the case where a fuel oil transfer pump(s) failure result in loss of capability of more than 1 EDG, a failure is counted for each affected EDG.