Enclosure 2

Reactor Oversight Process Task Force FAQ Log – February 19, 2015

FAQ Log Entering February 19, 2015 ROP WG Online Meeting

FAQ No.	PI	Topic	Status	Plant/Co.	Point of Contact
14-08	MS06	Prairie Island Lockout	Introduced 11/19/2014. Discussed 12/11/2014. NRC questions received in 12/11/2014 meeting are being addressed. Responses will be discussed at February 2015 meeting. *Responses to NRC questions to be discussed 2/19/2015*.	Generic	Laura Jean Noonan (Xcel) Karla Stoedter (NRC)
14-09	IE01	ANO Scram April 27, 2014	Introduced 12/11/2014. Staff response discussed 1/15/2015. *Revised staff response to be discussed 02/19/2015.*	Plant-Specific to ANO	Stephenie Pyle (Entergy) Matt Young (NRC)
14-10	PP01	Indian Point Security Upgrade	Introduced 12/11/2014. Discussed 01/15/2015. *To be discussed 02/19/2015.*	Plant-Specific to Indian Point 2,3	Brian Rokes (Entergy) NRC TBD
15-01 (Proposed)	IE04	Perry Scram, October 20, 2014	To be introduced 02/19/2015.	Generic	David Lockwood (First Energy) Mark Marshfield (NRC)

For more information, contact: James Slider, (202) 739-8015, jes@nei.org

Revised 02/18/2015

NEI 99-02 FAQ 14-XX (Proposed)
Prairie Island MSPI

Plant:	Prairie Island Nuclear Generating Station (PINGP) Unit 1
Date of Event:	June 23, 2014
Submittal Date:	November 18, 2014
Licensee Contact:	Laura Jean Noonan
	Tel/email: 651-267-6449 / Laura.Jean.Noonan@xenuclear.com
NRC Contact:	Karla Stoedter
	Tel/email: 651-388-1121 X4219

Performance Indicator:

MS06 – Emergency AC Power Systems

Site-Specific FAQ (see Appendix D)? No

FAQ to become effective: When approved

Question Section

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

Pg F-6 Lines 14-21:

Return to Service: Return to service is the transition from unavailable to available. A train/segment is "returned to service" when the following conditions are met: clearance tags have been removed, the train/segment has been aligned and prepared for operation, (e.g., valve line-up complete, system filled and vented), further adjustment of associated equipment is not required or expected as a result of the unavailability period, and operators concur that the train/segment is able to perform its expected functions. For standby equipment, automatic functions are aligned or can be promptly restored by an operator consistent with the requirements for crediting operator recovery stated later in this section.

Pg F-27 Lines 14-20:

Emergency power generator failure to load/run*:* Given that the emergency power generator has successfully started and the output breaker has received a signal to close, a failure of the generator output breaker to close or a failure to run/operate for one hour after breaker closure. The emergency power generator does not have to be fully loaded to count the failure. Failure to load/run also includes failures of the emergency power generator output breaker to re-close following a grid disturbance if the emergency power generator was running paralleled to the grid, provided breaker closure is required by plant design.

Pg F-28 Lines 39-46, Pg F-29 Lines 1-7

Human errors/component trips, inadvertent actuations or unplanned unavailability introduced as part of a test or maintenance activity are not indicative of the reliability of the equipment had the activity not been performed, and should NOT be counted as failures as long as they are immediately revealed and promptly reported to the control room.

This applies to human errors which result in tripping an MSPI component that:

1. Occur while the MSPI train/segment is considered available;
2. Do not result in actual equipment damage;
3. Are immediately revealed through clear and unambiguous indication;
4. Are promptly reported to the control room without delay prior to the performance of corrective actions, and;
5. Are clearly associated with a test or maintenance activity such that the failure sequence would not have occurred and cannot occur if the test or maintenance activity was not being performed.

Pg F-48 Lines 23-26

An EDG is not considered to have failed due to any of the following events:

- spurious operation of a trip that would be bypassed in a loss of offsite power event
- malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources)

Event or circumstances requiring guidance interpretation:

On June 23, 2014, a failed relay associated with a 345kV/161kV transformer (TR10) in the Prairie Island Nuclear Generating Plant (PINGP) switchyard resulted in the load tap changer receiving a signal to move to the lowest tap setting. This created a low voltage condition in the 161kV PINGP bus. As a result Engineered Safety Feature (ESF) Bus 15 was declared inoperable. The other ESF bus, Bus 16, was being energized from a different offsite source and did not experience a low voltage condition. Eventually the 161kV bus voltage dropped to less than 155kV which resulted in an undervoltage condition on Bus 15 and an auto start of Emergency Diesel Generator (EDG) D1 which then powered the loads on Bus 15.

The Control Room operators subsequently paralleled a different offsite source (CT11) with D1 in order to transfer the Bus 15 loads using procedure 1C20.7. This procedure includes a caution against allowing the load on D1 to drop to less than 100 kW to prevent motorizing the generator. This evolution is a restoration activity that procedurally requires declaring the diesel generator inoperable and unavailable.

D1 subsequently experienced a reverse power condition resulting in a trip and reverse power (86 relay) lockout. The lockout was caused by a reverse-power condition during the supply-source transfer of Bus 15 from D1 to CT11.

The trip of D1 was reported as an MSPI EAC load/run failure in the 2nd quarter of 2014; however, PINGP is seeking to retract the failure.

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

The NRC Resident agrees with the description of the event. However, it is not clear from NEI 99-02 whether this restoration activity would meet the definition of maintenance, or whether the event constitutes an MSPI failure.

Potentially relevant FAQs: None

<u>Response Section</u>

Proposed Resolution of FAQ:

The trip and reverse power lockout of D1 does not count as an MSPI failure.

Per the Prairie Island MSPI Basis Document, Revision 15, the MSPI monitored function for the Emergency AC System is “To provide emergency AC power to risk-significant equipment during loss of AC power conditions.” D1 was fulfilling this function by powering the loads on Bus 15 in response to the undervoltage condition.

The evolution of paralleling an emergency diesel generator to an offsite power source is considered a restoration activity by the site. For D1, this requires declaring the diesel inoperable and unavailable. Operator action is required to parallel to an alternate source, dial in droop on D1, and to open the emergency diesel generator output breaker.

The reverse power logic is a protective feature for when D1 is paralleled to a second power source. Although the reverse power trip and lockout logic are not bypassed during a loss of offsite power event, a valid reverse power condition is not possible when D1 is performing its monitored function.

The lockout condition was not indicative of the reliability of the equipment, and should not be counted as an MSPI failure. No equipment damage occurred. The lockout condition was immediately identified in the control room and corrected prior to D1 being returned to operable status.

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

> Pg F-28 beginning on line 39 should be clarified to reflect that events which are caused by human error that are not indicative of the reliability of the equipment should not be counted as failures:
>
> > Human errors/component trips, inadvertent actuations or unplanned unavailability which are not indicative of the reliability of the equipment had the activity not been performed, should NOT be counted as failures as long as they are immediately revealed and promptly reported to the control room.
> >
> > This applies to human errors which result in tripping an MSPI component whether or not the MSPI train/segment is considered available that:
> >
> > 1. Do not result in actual equipment damage;
> > 2. Are immediately revealed through clear and unambiguous indication;

3. Are promptly reported to the control room without delay prior to the performance of corrective actions, and;
4. Are clearly associated with an activity such that the failure sequence would not have occurred and cannot occur if the activity was not being performed.

Unavailability should be counted from the time of the event until the equipment is returned to service, and classified as unplanned unless provisions of *Counting Unavailability when Planned and Unplanned Maintenance are Performed in the Same Work Window* apply.

Latent failures (failures that existed prior to the maintenance) that are discovered as part of maintenance or test activity are considered failures.

PRA update required to implement this FAQ?

No

MSPI Basis Document update required to implement this FAQ?

No

Response to NRC Questions on FAQ 14-08, Prairie Island MSPI D1 EDG Trip

Following are responses to questions from the NRC on NEI 99-02 FAQ 14-08.

1. ***Under the section "NEI 99-02 Guidance needing interpretation," the FAQ includes the following reference: Pg F-48 Lines 23-26, "An EDG is not considered to have failed due to any of the following events: Spurious operation of a trip that would be bypassed in a loss of offsite power event; Malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources). Can the applicability of that section (Pg F-48) to this scenario be discussed further?***

   Response: As stated in the FAQ section quoted, the Prairie Island EDG lockout addressed in FAQ 14-18 is not a spurious operation of a trip which would be bypassed in a loss of offsite power event, nor is it a malfunction of equipment. The applicability of the quoted section of NEI 99-02 Pg F-48 is in the guidance directing no failure be counted for events which cannot impact the performance of an MSPI monitored function.

   A reverse power condition on the EDG would only occur when paralleling to another power source, such as during testing or restoration of ESF bus to offsite power source without a dead bus transfer. The EDG would not be paralleled to another power source in an emergency mode (e.g. during a loss of offsite power event). Following a loss of offsite power, the ESF bus is disconnected from other power supplies.

2. ***How long after the EDG D1 auto-started did the reverse power condition occur?***

   Response: The EDG auto-started and powered the safeguards bus at 1107 in response to a degraded voltage condition. The alternate source breaker to the safeguards bus, fed from CT11, was closed at 1139 with the EDG still aligned to the bus. The EDG experienced a reverse power trip and lockout prior to 1140, as the control room operators were transferring load off of the EDG to the alternate source and preparing to open the EDG output breaker. Therefore, the reverse power condition occurred 32 minutes after EDG auto-start and approximately 30 seconds after offsite power was restored to the safeguards bus.

3. ***In the discussion of events/circumstances the following observation is included: "This procedure includes a caution against allowing the load on D1 to drop to less than 100 kW to prevent motorizing the generator." Can you provide a brief discussion about this caution? Were there any operator actions related to that caution impacting the reverse power condition?***

   Response: The operators were briefed on this caution prior to performing steps placing the EDG parallel to another power source (CT11). The caution directed operator action (performance of a subsequent step) to prevent motorizing the EDG.

   Upon closure of the safeguards bus alternate source breaker to CT11, EDG load was over 100kW. The operator strictly adhered to procedure steps, reducing EDG load and VAR load using governor and exciter control switches. During performance of the intermediate step of adjusting VAR load, the EDG tripped on reverse power.

   Operator knowledge/performance resulted in zeroing in on one indication, and the caution was not applied. The procedure has been changed, removing the intermediate steps, and now conditionally adjusts EDG load to less than 500kW.

4. ***What is being considered a restoration activity? Why? What function is being restored?***

   Response: As stated in LER 2014-004-00, "Immediate action(s) taken, Bus 15 was restored to CT11 source from the D1 EDG source in accordance with site procedure."

   The restoration activity was returning the EDG to normal standby configuration and ESF Bus to an offsite power source. Restoring Bus 15 to an offsite power source and the D1 EDG to standby is a restoration activity because it places station equipment back to a normal/expected configuration.

   Restoring EDG standby configuration requires rendering the EDG inoperable and unavailable for its function "to provide emergency AC power to risk-significant equipment during loss of AC power conditions."

   The lockout condition was immediately identified in the control room and corrected prior to D1 being returned to operable status. No equipment damage occurred. The lockout condition was not indicative of the reliability of the equipment.

5. ***Why this is considered a test or maintenance activity?***

   Response: Placing the EDG in parallel to another power source was required to restore the EDG to standby following response to an actual ESF bus degraded voltage condition in the switchyard. Interpretation of the regulatory definition (Reference Federal Register, Vol. 53, No. 56, Wednesday March 23, 1988, Rules and Regulations Page 9340) of maintenance may be inclusive of this evolution. However, NEI 99-02 examples of test or maintenance activities do not include this, or other operational evolutions.

6. ***Why this event is/isn't representative of the following section of the definition of "Emergency power generator failure to load/run" in NEI 99-02? "Failure to load/run also includes failures of the emergency power generator output breaker to re-close following a grid disturbance if the emergency power generator was running paralleled to the grid, provided breaker closure is required by plant design."***

   Response: This section of NEI 99-02 addresses counting failures of the output breaker. No breaker failure occurred. In this event, all equipment functioned as designed in response to the conditions seen.

   Prairie Island plant design does not allow breaker re-closure following a loss of load without restoration.

NEI 99-02 FAQ 14-09
ANO Scram April 27, 2014

Plant: Arkansas Nuclear One Unit 2 (ANO-2)

Date of Event: April 27, 2014

Submittal Date: July 29, 2014

Licensee Contact: Stephenie Pyle Tel/email: 479-858-4704 / spyle@entergy.com

NRC Contact: Matt Young Tel/email: 479-858-3113 / matt.young@nrc.gov

Performance Indicator:

IE01 - Unplanned Scrams Per 7,000 Critical Hours

Site-Specific FAQ (see Appendix D)? No

FAQ to become effective: April 27, 2014

Question Section

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

Pg 10 Lines 11, 12, 13, 14

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.

Pg 10 Lines 33, 34

Anticipatory plant shutdowns intended to reduce the impact of external events, such as tornadoes or range fires threatening offsite power transmission lines, are excluded.

Pg 11 Lines 12, 13, 14

Scrams that are initiated at less than or equal to 35% reactor power in accordance with normal operating procedures (i.e.,not an abnormal or emergency operating procedure) to complete a planned shutdown and scram signals that occur while the reactor is shut down.

Event or circumstances requiring guidance interpretation:

On 4/27/14 the grid operator declared a grid emergency and requested that both units at ANO be immediately taken off line. Operators in the control room of ANO-2 commenced a rapid power reduction, following station procedures, in preparation for removing the generator from the grid, as requested by the grid operator. During the rapid power reduction a severe Axial Shape Index (ASI) transient developed. Severe ASI (Axial Shape Index – a measure of the neutron flux location in the core) transients are unavoidable when performing rapid plant shutdowns near the end of core life, as was the case for ANO-2.

The severity of these ASI transients presents a significant challenge to plant operators and an increased probability of a reactor trip. The only way to avoid severe ASI transients at this time in core life is to perform very slow power descents, which would not support the grid operator request in this event. During the rapid power reduction to take the ANO-2 unit offline, ASI rapidly approached operating limits and a manual scram was ordered. However, before the manual scram could be performed, the unit automatically tripped due to exceeding the ASI operating limit. Because the ASI transient was a direct result of a rapid shutdown excluded under the Anticipatory plant shutdown clause, Entergy believes the intent of the exclusion is met regardless of the method of reactor trip, which accomplished the same objective. Since plant shutdowns which are intended to reduce the impact of external events, in this case, tornadoes threatening offsite power transmission lines, are excluded from IE01, the ASI trip resulting from the rapid shutdown was not counted in the indicator value for ANO-2.

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

With respect to the example in the Unplanned Scrams Per 7,000 Critical Hours, Entergy has determined the shutdown on 4/27/14 to meet the "anticipatory" exclusion. The NRC Resident inspector has questioned whether the subject shutdown can be excluded as “anticipatory” since the ASI trip occurred at ~50% prior to the power level of 20% when the procedure for rapid shutdown would have directed a manual scram.

Potentially relevant FAQs:

FAQ 469

<u>Response Section</u>

Proposed Resolution of FAQ:

Due to the reduction of available offsite power transmission lines that provided power to Little Rock after the Mayflower power transmission substation was damaged from the 4/27/14 tornado, the subsequent ANO-2 shutdown should be considered "anticipatory". This anticipatory shutdown was necessary to protect the three remaining 500 kV transmission lines going into Little Rock from sustained overload conditions, over 120%.

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

None

PRA update required to implement this FAQ? No

MSPI Basis Document update required to implement this FAQ? No

<u>NRC Response</u>

<u>This FAQ discusses a reactor trip event at ANO Unit 2 that occurred on April 27, 2014, after an Axial Shape Index (ASI) transient developed while performing a rapid shutdown. The licensee indicated that the grid operator requested both ANO units to be taken out off line immediately and it had to perform a</u>

rapid shutdown to fulfill such request. The licensee also indicated that ANO Unit 2 was near the end of core life and an ASI transient was unavoidable. The licensee proposed that this event should be considered an "anticipatory" shutdown that was necessary to protect power transmission lines and it should not count as an unplanned scram.

The NRC staff reviewed the information provided by the licensee in this FAQ and the Licensee Event Report (LER) for this event. The staff understands that the grid operator requested to take both ANO Units off line as soon as possible and that the cause for the ASI trip was an ineffective application of the reactivity management plan while performing the rapid shutdown.

The NRC staff also reviewed the following sections of NEI 999-02 as applicable to this FAQ.

Pg 12, Ln 1, 2
A scram that occurs during the execution of a procedure or evolution in which there is a high likelihood of a scram occurring but the scram was neither planned nor intended.

The guidance in NEI 99-02 acknowledges that there are plant evolutions with high likelihood to result in a scram (as in the case of this FAQ) and that such scrams should be counted as unplanned if these were not planned or intended. In this event, the licensee understood that this evolution was likely to result in a scram, but did not plan or intend for a scram to occur automatically as a result of an ASI trip. Even though the ASI transient occurred, following the reactivity management plan accordingly could have lessened the severity of such transient.

Pg 12, Ln 12, 13, 14
Scrams that are initiated at less than or equal to 35% reactor power in accordance with normal operating procedures (i.e., not an abnormal or emergency operating procedure) to complete a planned shutdown and scram signals that occur while the reactor is shut down.

The automatic ASI trip occurred at about 50% power level. According to the FAQ, the rapid shutdown process would prompt the operator to manually scram the plant at 20% power. However, the plant had an automatic scram above 35% power and the manual scram as intended by the rapid shutdown procedure could not be performed.

The staff concluded that this event should count as an unplanned scram. While this shutdown was performed in response to a grid request, the licensee was aware that this evolution presented a high likelihood of a scram and failed to successfully complete the rapid shutdown procedure due to poor execution of the reactivity management plan.

Record of Changes:
01/13/2015 – Draft NRC response was added.

FAQ 14-10
Indian Point Security Upgrade

Plant: _Indian Point___
Date of Event: __NA_____
Submittal Date: __December 11, 2014___
Licensee Contact: __Brian Rokes____ **Tel/email**: 914-254-6674 CRokes@entergy.com
NRC Contact: ________________ Tel/email: __________________

Performance Indicator: PP01

Site-Specific FAQ (Appendix D)? Yes

FAQ requested to become effective: when approved

Question Section

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

Event or circumstances requiring guidance interpretation:
Indian Point Unit 2 and 3 each have their own security computer, independent of the other unit resulting in a different security indicator for each unit. The station currently reports two separate and distinct security performance indicators, one for Unit 2 and one for Unit 3 In early 2015, a new security computer system will be made operational, which will result in a single site wide system. This site-specific FAQ requests guidance on how to best handle that transition when it occurs.

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
The site proposes to maintain two separate security indicators, one for Unit 2 and one for Unit 3.

Future Data
Once the site security system is integrated, the security performance indicator for both units will be annotated with a "licensee comment" indicating that the security system has been combined into a site indicator. Entergy will work with INPO to revise the normalization factors to reflect the new combined system. For future data reporting, the performance indicators, although two separate files, will contain identical information, each reflecting current site performance.

Past Data (prior to site security computer integration)
~~For historical data presentation, Entergy proposes to maintain two separate indicators (one for Unit 2 and one for Unit 3).~~ The indicator for the Units will reflect the performance of the unit specific security system, up to the point where the system was integrated, at which point the performance line will shift to reflect the new station value. A "licensee comment" will be

included on the indicator stating that data included before the integration date reflects a unit specific value, versus a site specific value.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
None

PRA update required to implement this FAQ
No

MSPI Basis document update required to implement this FAQ?
No.

Record of Changes
Original file – December 5, 2014.
January 13, 2015 - Added serial number 14-10 to the title of the FAQ.
February 3, 2015 – Deleted mention of adding a licensee comment in the data submittal, as discussed at Jan. 15, 2015 ROP meeting with NRC.

Plant: Perry
Date of Event: October 20, 2014
Submittal Date:
Licensee Contact: David Lockwood **Tel/email:** (440)280-5200/ dhlockwood@firstenergycorp.com
NRC Contact: Mark Marshfield **Tel/email:** (440) 280-5822/mark.marshfield@nrc.gov

Performance Indicator: IE04, Unplanned Scrams With Complications

Site-Specific FAQ (see Appendix D) (__) Yes or (X) No

FAQ requested to become effective (_X_) when approved or (other date):

Question Section

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

BWR flowchart question: Did an RPS actuation fail to indicate/establish a shutdown rod pattern for a cold clean core. Page 25, lines 3 through 22.

> **Did an RPS actuation fail to indicate / establish a shutdown rod pattern for a cold clean** core**?**
>
> Withdrawn control rods are required to be inserted to ensure the reactor will remain shutdown under all conditions without boron to ensure the reactor will have the required shutdown margin in a cold, xenon-free state.
>
> Any initial evaluation that calls into question the shutdown condition of the reactor requires this question to be answered "Yes." The required entry into the Anticipated Transient without Scram (ATWS) leg of the EOP or required use of Alternate Rod Insertion (ARI) requires this question to be answered "Yes." Failure of the rod position indication in conjunction with the loss of full-in-lights on enough rods to question the cold clean core shutdown status would require this question to be answered "Yes."
>
> The basis of this step is to determine if additional actions are required by the operators to ensure the plant remains shutdown as a result of the failure of any withdrawn rods to insert (or indicate inserted). Additional actions, such as boron injection, or other actions to insert control rods to maintain shutdown, pose a complication beyond a normal scram response. This question must be evaluated using the criteria contained in the plant EOP used to verify the insertion of withdrawn control rods.

Appendix H, USwC Basis Document, Section H3.1, page H-17, lines 36 through 44, and page H-18, lines 1 through 12.

> The purpose of this question is to verify that the reactor actually tripped and had sufficient indication for operations to verify the trip. As long as a plant uses the EOP questions to verify that the reactor tripped without entering the level/pressure control leg of the EOPs, the response to this question should be "No".

The generic BWROG EPG/SAG Revision 2 Appendix B statement is offered as an example:

Any control rod that cannot be determined to be inserted to or beyond position [02] (Maximum Subcritical Banked Withdrawal Position)] and it has not been determined that the reactor will remain shutdown under all conditions without boron, enter Level/Power Control.

For example:
Are all control rods inserted to or beyond position 02 (if no then this is a yes for this PI)? Will the reactor remain subcritical under all conditions without boron (if no then this is a "Yes" for this PI)?

For example:
All rods not fully inserted; and, the reactor will not remain shutdown under all conditions without boron then enter level/pressure control (if yes then this is a "Yes" for this PI).

Event or circumstances requiring guidance interpretation:

While operating at 100% power, an unplanned automatic reactor scram occurred due to Reactor Pressure Vessel (RPV) Level 3 (178") activation of the Reactor Protection System. An electrical transient occurred impacting Feedwater Level Control. The reactor mode switch was placed in Shutdown in accordance with plant operating procedures.

Prior to the scram, Feedwater was aligned with the Reactor Feed Pump Turbines (RFPT) A & B in automatic Digital Feedwater Three Element (3E) control. The Motor Feedwater Pump (MFP) was in Standby. The RPV Level 3 signal was the result of RFPT's A/B no longer providing adequate feedwater to the RPV due to an electrical transient. The RPV water level continued to lower to Level 2 which resulted in a valid initiation of both Reactor Core Isolation Cooling (RCIC) and High Pressure Core Spray (HPCS) and associated support systems. The RCIC initiation provided a Main Turbine trip signal as expected. The Motor Feed Pump, HPCS, and RCIC all tripped when RPV Level 8 was achieved. EOP-1, RPV Control, was entered by the Unit Supervisor due to RPV Level 2 (130").

When Level 2 was reached ARI was automatically initiated by the Redundant Reactivity Control System as designed. This actuation is based on Level 2 only and occurs regardless of control rod position.

Upon the scram signal, the Full Core Display was indicating both Red and Green LED Lights (Rods Out and In, respectively) where the expected response was all Green LED Lights. The Rod Action Control System (RACS) was utilized to verify that the "All Rods In" LED was illuminated, and this was verified by multiple operators. The Rod Control Information System was reset utilizing the plant procedure and indication returned to normal, all Green. The erroneous indication was caused by the electrical transient that occurred from the DB1A inverter. Actuation of alternate reactivity controls by the operators was not required.

The RACS is located in a control room back panel outside of the "at the controls" area of the control room. RACS is a subsystem of Rod Control and Information System. There is two divisions of RACS. The RACS 'All Rods In" LED will actuate when the full-in limit switch on the position indicating probe (PIP) for all control rods has actuated. There are two limit switches per PIP each providing input to a separate division. Operators have received training on using the RACS ‘All Rods In” LED to verify a shutdown rod pattern, however this use is not proceduralized.

Perry has determined that this event is not an Unplanned Scram with Complications based on the guidance on page 25 lines 17 through 22, which state:

“The basis of this step is to determine if additional actions are required by the operators to ensure the plant remains shutdown as a result of the failure of any withdrawn rods to insert (or indicate inserted). Additional actions, such as boron injection, or other actions to insert control rods to maintain shutdown, pose a complication beyond a normal scram response. This question must be evaluated using the criteria contained in the plant EOP used to verify the insertion of withdrawn control rods.”

The initial evaluation verifying the shutdown condition of the reactor utilizing the RACS indication when the Full Core Display had conflicting information was correct. The operators were able to determine that all rods were inserted and the reactor would remain shutdown under all conditions without boron and entry into the Level/Power Control leg of the EOPs was not required.

Appendix H section H3.1 supports this determination at lines 39-42 on page H-17 which states;

“The purpose of this question is to verify that the reactor actually tripped and had sufficient indication for operations to verify the trip. As long as a plant uses the EOP questions to verify that the reactor tripped without entering the level/pressure control leg of the EOPs, the response to this question should be “No”.”

Appendix H, Section H4.1, BWR Case Study 1, and Section H4.2, BWR Case Study 2, both indicate that this question is focused on the actual condition of the reactor and whether additional actions are taken to ensure the reactor would remain shutdown under cold clean conditions. In both case studies this question can be answered “No” as Alternate Rod Insertion was not indicated or required.

BWR Case Study 1 includes, as an example of an acceptable “no” answer, the following explanation: “While all rods did not fully insert, reactor engineering, using an approved procedure, ran a computer calculation that determined the reactor would remain shutdown under cold clean conditions.” In the Perry case, all rods did insert, and observing the “All Rods In” LED is less complicated than running a computer calculation

In the Perry event of October 20, 2014, operator action to initiate ARI was not indicated or required, entry into the Level/Power Control leg of the EOPs was not required and sufficient indication (RACS) was available for the operators to determine that all rods were inserted.

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

The Resident Inspector Office has contacted NRR and believes that utilizing a back-panel indication (i.e. RACS, which happens to be located in the control room at Perry but requires entry into a panel to validate indications) is an additional action not required in the immediate actions for the at-the-controls operator (ATC). As such, the requirement for additional personnel actions to validate a clean cold core, utilizing a single status indicating light on only one division of RACS as in this case, does not equate to completing the “immediate” action step on the At-the-Controls hard card to indicate a cold clean core. On page 25 of

NEI 99-02, lines 13-15, the flowchart guidance states “Failure of the rod position indication in conjunction with the loss of full-in-lights on enough rods to question the cold clean core shutdown status would require this question to be answered ‘Yes.’” During the October 20, 2014 scram, the ATC was unable to make an initial determination that he had a cold clean core from the indications available to him and requested an additional operator to go back-panel to evaluate the indication in RACS, this demonstrated that the “initial evaluation of a cold clean core” was indeed indeterminate. With regard to the case studies, ARI was actuated at Perry during this scram because it is automatic on Level 2 which was reached during this scram so by definition it was required. Further, if the control room was at minimum manning, with no one immediately available to go back-panel, the ATC on watch in the control room would take the immediate action to actuate ARI and RPS as required by the hard card and the answer would again be “Yes” to block 1 of the flowchart for complicated scrams.
Potentially relevant FAQs: None identified.

Response Section

Proposed Resolution of FAQ:

Revise the response to the BWR flowchart question: Did an RPS actuation fail to indicate/establish a shutdown rod pattern for a cold clean core. Page 25, lines 3 through 22 to align with Appendix H, USwC Basis Document, Section H3.1, page H-17, lines 39 through 44, and page 18, lines 1 through 12. Specifically, clarify that a scram with complications results only from entry into the Level/Power Control leg of the EOPs
If appropriate, provide proposed rewording of guidance for inclusion in next revision:

On page 25 at line 10 delete the sentence which reads “Any initial evaluation that calls into question the shutdown condition of the reactor requires this question to be answered “Yes.””

On page 25 at line 17 revise this sentence to read “The basis of this step is to determine if additional actions are required by the operators to ensure the plant remains shutdown as a result of the failure of any withdrawn rods to insert.

PRA update required to implement this FAQ? No
MSPI Basis Document update required to implement this FAQ? No