Upcoming changes to IMC 0305, "Power Reactor Assessment Program"

- Replace existing guidance for Action Matrix movement with:

  If inspection findings are extended beyond the original four quarters, the plant can change Action Matrix columns upon successful completion of the supplemental inspection and issuance of the associated inspection report (or other agency action), and an assessment follow-up letter noting the change in column. However, the findings will still be considered in the Action Matrix for aggregation purposes for the remainder of the quarter.

- Clarification on the Action Matrix of public stakeholder interaction options for Columns 1 and 2
- Consideration of operating experience during mid-cycle and end-of-cycle reviews
- Minor enhancements to reflect changes to IP 71152, "Identification and Resolution of Problems"
- Relocation of guidance relating to cross-cutting aspects
- Clarification that final significance determinations being formally appealed using the IMC 0609, "Significance Determination Process," Attachment 2, appeal process do count as Action Matrix inputs while under appeal
- Endorsing the use of the deviation process for long-standing substantive cross-cutting issues
- Various administrative enhancements

In addition to changes to IMC 0305, the Action Matrix Summary website will be redesigned as part of the 3rd quarter 2009 data update.

Staff White Paper

EDG Component Boundary (Fuel Oil Transfer Pump Issue)

Super Component Approach

Issue

This paper summarizes the proposed simplified fuel oil transfer pump (FOTP) modeling approach as discussed at the September 16th MSPI public meeting.

Approach

(1) Fuel oil system failures that result in an EDG failure or could have resulted in an EDG failure will be scored as an EDG run failure.

(2) A fuel oil system failure is only counted as an EDG run failure if it meets the following conditions:

a) The fuel oil system failure that results in an EDG failure or could have resulted in a failure of an EDG where the EDG would not be capable of performing its function for its PRA mission time. For example, assume an EDG with a PRA mission time of 8 hours. A fuel oil system failure that results in a failure or could have resulted in a failure at 10 hours would not be an EDG run failure. A fuel oil system failure that results in a failure at 1 to 8 hours would be an EDG run failure.

b) A FOTP control system failure (e.g., flow switch) that results in an EDG failure or could have resulted in a failure as defined in Criterion (a) above is to be counted as an EDG run failure.

c) A fuel oil system failure that results in multiple EDG failures (e.g., one pump supporting two EDGs) shall be scored as a failure against each impacted EDG (i.e., a failure of one pump that supports two EDGs results is two EDG failures.)

d) An EDG that is secured early (within the first hour) as a result of a fuel oil system failure that is likely to occur after one hour is scored as an EDG run failure.

(3) An EDG fuel oil system failure that results in a EDG failure or could have resulted in a failure within the first hour of operation is a load-run failure. Failures where the EDG is secured early but are likely to have occurred after one hour are to be scored as indicated by 2(d).

(4) Fuel oil system components that are not required to function for the EDG to achieve its PRA mission are excluded from the MSPI EAC system scope.

(5) Detailed FO system scoping is not required: However, all FO pump failures will need to be assessed to ensure that they do not meet the failure definition as described above. Estimates of day tank size in terms of EDG loaded run hours and their basis should be included in the MSPI Basis Documents.

(6) Recovery actions including the use of hand-operated pumps cannot be credited as preventing an EDG failure.

(7) Baseline EDG failure data will be reviewed to determine if revised baseline values are required.

Why does staff need updated MSPI Basis Documents?

1) Provide an updated reference resource
2) Provide updated EDG mission times for review and reference
3) Provide resource to aid in the resolution of data quality issue
    a. Provides current basis for planned baseline unavailability
4) Enable Basis document comparison reviews between plants
    a. Outlier reviews
5) Provide evidence that basis documents are being maintained
    a. Regulatory and Public confidence

What are the key items that should be included in the updated documents?

1) The current baseline planned unavailability and its basis
2) The PRA EDG mission time
3) If possible, the day tank capacity (as measured by loaded EDG run hours) (it may be worth waiting until the FOTP issue is resolved before receiving updates)

Why not have NRC residents review the Basis documents?

Having a central set of basis document enables:

a. An updated reference library
b. Enables MSPI knowledgeable personnel to perform programmatic assessments and outlier reviews
c. Limits resource burden of residents and would likely be more efficient for industry as the request would be consistent across the industry.

Is this a one-time request?

Staff envisions that it will requests updates every few years following significant MSPI program changes.

Existing Guidance on Page E-3 Beginning at line 25

Withdrawal of FAQs

A licensee may withdraw a FAQ after it has been accepted by the joint ROP Working Group. Withdrawals must occur during an ROP Working Group monthly (approximately) meeting. However, the ROP Working Group should further discuss and decide if a guidance issue exists in NEI 99-02 that requires additional clarification. If additional clarification is needed then the original FAQ should be revised to become a generic FAQ.

Recommended Change

Withdrawal of FAQs

A licensee may withdraw a FAQ after it has been accepted by the joint ROP Working Group. Withdrawals must occur during an ROP Working Group monthly (approximately) meeting. However, the ROP Working Group should further discuss and decide if a guidance issue exists in NEI 99-02 that requires additional clarification. If additional clarification is needed then the original FAQ should be revised to become a generic FAQ. *In many cases, there are lessons learned from the resources expended by the ROP Working Group that should be captured. In those cases, the FAQ will be entered in the FAQ log as a generic FAQ. If there is disagreement between the staff and industry, both positions should be articulated in the FAQ. These withdrawn FAQs should be considered as historical and are not considered to be part of NEI 99-02. They should not be used as precedence in future discussions.*

Temp No.	PI	Topic	Status	Plant / Co.
09-04	IE04	Loss of FW after scram	Tentative Approval	Brunswick
09-05	IE03	Outside Licensee Control	Discussed	ANO
09-06	EP01	Offsite Call Simulation	Discussed	DAEC
09-07	MSPI	Changes to Planned Unavailability Baseline	Discussed	Generic
09-08	MSPI	PMT Failures when Available but not Operable	Tentative Approval	Generic
09-09	IE03	Unplanned Power Changes	Introduced	Generic

FAQ

Plant: Brunswick Unit 1
Date of Event: 11/26/2008
Submittal date: 01/30/2009
Licensee Contact: Lee Grzeck Tel/email: 910-457-2487 / lee.grzeck@pgnmail.com
NRC Contact: Phil O'Bryan Tel/email: 910-457-2831 / philip.o'bryan@pgnmail.com

Performance Indicator: IE04 - Unplanned Scram with Complications
Site-Specific FAQ (Appendix D)? No
FAQ requested to become effective when approved.

QUESTION

NEI 99-02 Guidance needing interpretation:

Page 21-22, "Was Main Feedwater not available or not recoverable using approved plant procedures?"

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response?[1] The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary.[2] 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 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 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 30 minutes.[3] During startup conditions where Main Feedwater was not placed in service prior to the scram, the question would not be considered, and should be skipped.

Event or circumstances requiring guidance interpretation:

On 11/26/2008, at 1200 hours (EST), Unit 1 scrammed when a Group 1 primary containment isolation occurred, resulting in an automatic actuation of the Reactor Protection system. Investigation determined that a pressure-load gate amplifier circuit board in the Electro-Hydraulic Control (EHC) system operated erroneously. The Main Steam (MS) isolation valves (MSIVs) closed on the Group 1 isolation. As designed and described in Brunswick operating procedures, following a Group 1 isolation with the MSIVs closed, Reactor Core Isolation Cooling (RCIC) was used to effectively maintain reactor water level. At approximately 1241 hours, IAW 1OP-25 (MS System Operating Procedure), low condenser vacuum switches are placed in bypass to support resetting the Group 1 isolation. A few steps later, the Main Steam supply valve 1-MS-V28 is closed by the Operator in preparation for re-opening the MSIVs (this valve provides main steam to the Reactor Feed Pumps). Note that during the approximately 40 minutes of the initial scram response the 1-MS-V28 valve remained open and available. At 1511, Operations reopened the MSIVs, per 1OP-25. A few steps later, an attempt was made to open the Main Steam supply valve 1-MS-V28 from the Control Room, but the valve did not open. An attempt was made to manually open the valve, however, the valve was thermally bound and would not open. Main Feedwater was not needed for reactor water level control, as RCIC was being effectively utilized for level control. Engineering was contacted to provide torque values to be used to open the valve. After shift turnover, and early in the next shift (after 1800 hours), the Operators attempted to manually open the 1-MS-V28 valve with the use of the provided torque values, however they found the valve was no longer thermally bound closed and opened it by hand.

<u>Questions requiring interpretation:</u>

[1] - The first line of the guidance states "did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response?"

> Main Feedwater (FW) ceased to operate upon the Group 1 isolation (MS lines, MS drain lines, Recirc sample valves). Immediately following the scram, an expected reactor vessel coolant level shrink occurred. As a result of the low water level, primary containment Group 2 (DW equipment and floor drains, TIPs, RHR discharge to RW, and RHR process sample valves) and Group 6 (CAC/CAD, CAM, and Post-Accident Sampling system) isolation signals were received. All required isolations occurred properly as a result of the reactor low water level isolation signals. All control rods fully inserted on the scram and all safety-related systems responded as designed. No Safety Relief Valves (SRVs) lifted during the scram. Per established procedures, the RCIC system was manually started to restore reactor water level to the normal band (note that RCIC is used for both level and pressure control).
>
> Normal operating procedure following a Group 1 isolation (with MSIVs closed) is to use RCIC for feeding the reactor vessel. It wasn't until approximately three hours and fifteen minutes after the scram occurred that Operations began the system alignment to get MS, and thus FW, back. At that point, the reactor scram response was essentially complete and recovery actions were in progress. The failure of the 1-MS-V28 valve to initially open at a later time and allow the restart of FW did not impact Operator response during the initial transient. No additional procedures were entered beyond the normal scram response procedure.

[2] - From the second sentence in the guidance, "The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary."

> Per design, Main Feedwater ceased to operate once the Group 1 isolation occurred, and per procedure, RCIC was successfully used to maintain reactor water level. Main Feedwater

was not required as part of the normal scram response procedure. This scram presented no significant challenges to the Operations personnel during the reactor scram response, and normal operating procedures were used.

[3] - Guidance states that "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 30 minutes."

During the first 41 minutes (approximate) of the initial reactor scram response, valve 1-MS-V28 remained open, and thus not subject to the thermal binding conditions encountered approximately three hours later. As noted above, it wasn't until approximately three hours and fifteen minutes after the scram occurred that Operations began the system alignment to get MS, and thus FW, back. There was no attempt to use Main Feedwater "during the reactor scram response," as RCIC was providing adequate feed to the reactor vessel. As previously described, this is the preferred method of reactor water inventory control following a Group 1 isolation.

In summary, Main Feedwater was capable of being restored to feed the reactor vessel in a reasonable amount of time. It is believed that within the first 30 minutes following the scram, with valve 1-MS-V28 still open, Main Feedwater was available as a source to provide reactor vessel level if needed. However, the timeline of events discussed above does not allow Brunswick to quantify that timeframe as prescribed in NEI 99-02. Thus, the NEI 99-02 guidance requires clarification as to what constitutes the "reactor scram response," and at what point are the entry conditions for the indicator exited.

NRC Senior Resident Inspector position:

"For this event specifically, I think the question boils down to – could main feed have been restored had RCIC and HPCI not functioned correctly? For the first 40 minutes after the scram when the steam isolation valve to main feed was open, would the same sequence of events occurred if operators tried to restore main feed , i.e. would the valve have been shut during restoration and subjected to the same conditions that caused the thermal binding? If not, then you probably have a good argument for no complications. If the valve would have been subjected to the same conditions that caused the thermal binding, then I think it should be classified as a scram with complications."

The NRC Senior Resident Inspector also does not agree with the proposed rewording of the guidance. For the proposed change to Page 21 (see the Response on the following page), "it would not capture those events that are of higher safety significance because main feed is not available, even if it was not required to be used," and "30 minutes is a completely arbitrary number." Similarly for the proposed change to page 22, even if the main feed steam supply is temporarily isolated, the PI should capture those events where main feed couldn't be restored in a relatively short time. "It might be different if the equipment was designed such that restoration was not possible, but in this case main feed should have been available and it was not." For our situation, he asked what would've happened if RCIC quit operating after an hour or hour and a half, i.e., at some time following 1241 when 1-MS-V28 was closed. The activity to restart Feedwater at that point should still be considered part of the scram response.

Potentially relevant existing FAQ numbers: None.

RESPONSE

Proposed Resolution of FAQ:

This event should not count against the Unplanned Scrams w/Complications PI.

This event did not lend itself well to determining if a Scram with Complications occurred based on the specific narrow focus of the questions in the flowchart on page 19 of NEI 99-02, Revision 5. This guidance focuses on whether feedwater was available for the first 30 minutes into the event, or approximately what could be considered the "scram response phase" of the transient. In this situation for the event in question, it is likely that feedwater was available for the first 30 minutes, so this event should not count against the indicator based on the current wording of the guidance. However, the guidance in NEI 99-02, Revision 5 should be reviewed to see if it needs to be revised based on circumstances that might require the availability of feedwater beyond 30 minutes and whether consideration of the scram response time window remains an appropriate marker for judging a complication to recovery from an unplanned scram. These questions will be addressed in a subsequent generic FAQ.

Plant: Arkansas Nuclear One

Date of Event: N/A – Generic Issue

Submittal Date: August 01, 2009

Licensee Contact: Steve Coffman, Entergy Tel: 479-858-5560 email: scoffma@entergy.com

NRC Contact: ____________ Tel: ____________ email: ____________

Performance Indicator: **Unplanned Power Changes Per 7000 Critical Hours**

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section:

This FAQ seeks clarification to the Unplanned Power Changes Per 7000 Critical Hours Performance Indicator guidance. There has been industry discussion as to whether or not activity and equipment in an local electrical switchyard at a nuclear facility is under the direct control of the nuclear plant management and within the scope of this Performance Indicator. Revision 5 of NEI 99-02 page 15 lines 8-10 state: ***"Power changes directed by the load dispatcher...for grid stability, or for nuclear plant safety concerns arising from external events outside control of the nuclear unit are not included in this indicator. However, power reductions due to equipment failures that are under the control of the nuclear unit are included in this indicator."***

In many cases, the Nuclear Operating Company does not own, or operate the equipment in the station switchyard, and switchyard maintenance is not performed under the Nuclear Operating Company procedures, but is performed by the Transmission Company employees under the control of the system dispatcher. In these cases, transients caused by equipment malfunctions or personnel errors should be considered outside the control of the nuclear unit for the purposes and scope of this performance indicator.

NEI 99-02 does not specifically define "outside the control of the nuclear unit." However, this terminology could be interpreted consistently with other industry uses of the same terminology. The IEEE 762 definition of "outside the control of plant management" is incorporated into the North American Electric Reliability Corporation's (NERC) Generation Availability Data System (GADS) reporting.

From the NERC-GADS reporting guidance, Unit Boundaries and Problems Outside Plant Control:
"Based on research by the IEEE 762 committee, the boundary between the GENCO (generating company)and TRANSCO (transmission company) is as follows: A generating unit includes all equipment up to (in preferred order) (1) the high-voltage terminals of the generator step-up (GSU) transformer and the station service transformers; (2) the GSU transformer (load) side of the generator-voltage circuit breakers; or (3) at such equipment boundary as may be reasonable considering the design and configuration of the generating unit."

NRC REG Guide 1.16 (Monitoring the Effectiveness of Maintenance at Nuclear Power Reactors) provides guidance when interpreting the definition of "outside the control of plant management, as it pertains to the Maintenance Rule. Under the Regulatory Position Section 3 (Inclusion of Electrical Distribution Equipment), RG 1.16 states: "Maintenance activities that occur in the switchyard can directly affect plant operations; as a result, electrical distribution equipment **out to the first inter-tie with the offsite distribution system** (i.e., equipment in the switchyard) should be considered for inclusion as defined in 10 CFR 50.65(b)." In many cases, the first inter-ties to the offsite distribution system are the Main Generator Output Breakers in the switchyard.

Proposed FAQ Response:

To clarify the physical boundary for "outside the control of nuclear plant management," the following statement will be added to NEI 99-02, page 15, after line 12:

11 However, power reductions due to equipment failures that are under the control of the nuclear
12 unit are included in this indicator**. For the purposes of this performance indicator, switchyard electrical distribution equipment and maintenance beyond the first inter-tie with the offsite distribution system is not considered "under the control of the nuclear unit" when the equipment is not owned by the nuclear operating company, and the maintenance is being performed by personnel other than nuclear operating company employees. Transients caused by work activities performed by nuclear operating company employees in the switchyard are considered within the scope of this indicator.**

References:

NEI 99-02 Revision 5 Page 14
38 Anticipatory power reductions intended to reduce the impact of external events such as
39 hurricanes or range fires threatening offsite power transmission lines, and power changes
40 requested by the system load dispatchers, are excluded.

NEI 99-02 Revision 5 Page 15
8 Power changes directed by the load dispatcher under normal operating conditions due to load
9 demand, for economic reasons, for grid stability, or for nuclear plant safety concerns arising
10 from external events outside the control of the nuclear unit are not included in this indicator.
11 However, power reductions due to equipment failures that are under the control of the nuclear
12 unit are included in this indicator.

Reg Guide 1.16 Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.

C. Regulatory Position

3. INCLUSION OF ELECTRICAL DISTRIBUTION EQUIPMENT

The monitoring efforts under the maintenance rule, as defined in 10 CFR 50.65(b), encompass those SSCs that directly and significantly affect plant operations, regardless of what organization actually performs the maintenance activities. Maintenance activities that occur in the switchyard can directly affect plant operations; as a result, electrical distribution equipment out to the first inter-tie with the offsite distribution system (i.e., equipment in the switchyard) should be considered for inclusion as defined in 10 CFR 50.65(b).

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL-Generation Availability Reporting Guidance:

UNIT BOUNDARIES AND PROBLEMS OUTSIDE PLANT CONTROL

A number of generating companies have been deregulated over the last several years. As a result, part of the GADS database contains deregulated units and part regulated units. As more and more electric utilities divide into generating companies (GENCO), transmission companies (TRANSCO) and distribution companies (DISCO), GADS must also make changes to accommodate the needs. To do so, we must determine where the GENCO responsibilities end and the TRANSCO take over. Based on research by the **IEEE 762** committee, the boundary between the GENCO and TRANSCO is as follows: **"**A generating unit includes all equipment up to (in preferred order) (1) the high-voltage terminals of the generator step-up (GSU) transformer and the station service transformers; (2) the GSU transformer (load) side of the generator-voltage circuit breakers; or (3) at such equipment boundary as may be reasonable considering the design and configuration of the generating unit." Not all plants have the high-voltage terminals of the generator step-up (GSU) transformer and the station service transformers as shown in (1) above. Therefore, the boundaries are shown in preferred order based on unit design. If (1) is not applicable, then (2); if not (2) then (3).

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL-Generation Availability Reporting Guidance Appendix K: Outside of Plant Management Control.

"The [**IEEE 762**] standard sets a boundary on the generator side of the power station (see Figure D-1, below) for the determination of equipment "outside management control"

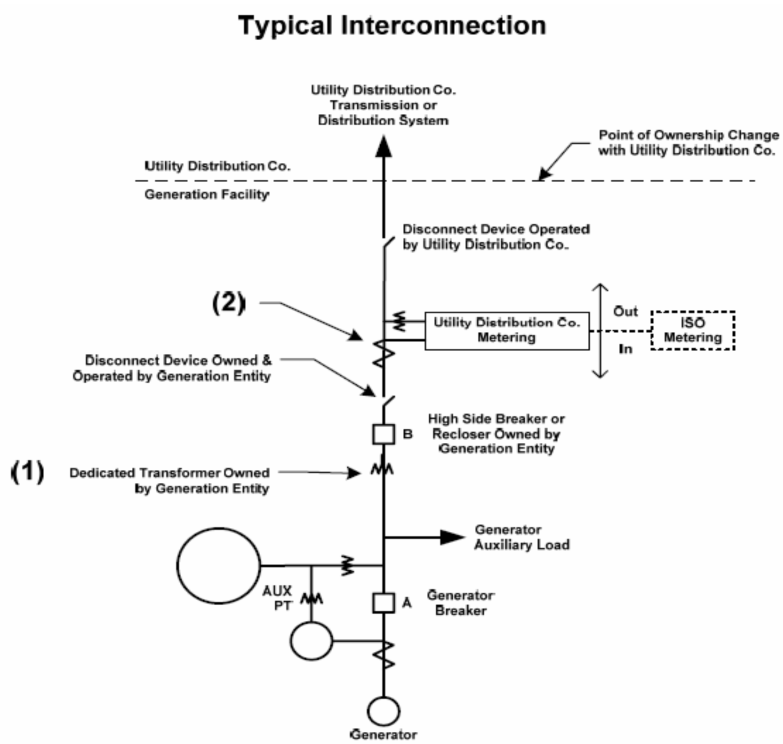

Figure D-1. The Physical Boundary of Outside Management Control

Appendix K – Outside Plant Management Control

Page K-2, 1/2008 GADS DATA REPORTING INSTRUCTIONS

"As shown in Figure D-1, a generating unit includes all equipment up to (in preferred order) (1) the high-voltage terminals of the generator step-up (GSU) transformer and the station service transformers; (2) the GSU transformer (load) side of the generator-voltage circuit breakers; or (3) at such equipment boundary as may be reasonable considering the design and configuration of the generating unit.

Plant: Duane Arnold Energy Center
Date of Event: 6/24/09
Submittal Date: 7/21/09
Licensee Contact: Mike Davis, Bob Murrell
Tel/email: 319-851-7032/ michael.davis@nexteraenergy.com
319-851-7900/ robert.murrell@nexteraenergy.com
NRC Contact: Randy Baker Tel/email: 319-851-7210

Performance Indicator: **Drill and Exercise Performance**

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

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

NEI 99-02, Rev. 5 page 45, lines 39 – 42:

> *Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification.*

NEI 99-02, Rev. 5 page 46, lines 13 – 15:

> *Simulation of notification to offsite agencies is allowed. It is not expected that State/local agencies be available to support all drills conducted by licensees. The drill should reasonably simulate the contact and the participants should demonstrate their ability to use the equipment.*

Event or circumstances requiring guidance interpretation:

In accordance with Duane Arnold Energy Center (DAEC) procedures for making offsite notifications of emergency events, the Shift Technical Advisor (Key Communicator) fills out the notification form, gains approval from the Shift Manager (Key Decision Maker/Emergency Director), and hands the form off to the Security Shift Supervisor (not filling an NRC Participation PI key position). The Security Shift Supervisor then contacts offsite authorities using a telephone system (one call notifies all county and state authorities).

During licensed operator continuing training simulator evaluations, Security personnel are sometimes not available to participate. In these cases, the simulator instructor/evaluator role-plays as the Security Shift Supervisor. When this occurs, the instructor does not pick up the phone and simulate making a call to offsite authorities.

The NRC resident has challenged counting these as successful DEP opportunities because there is no demonstration of using the phone equipment.

NEI 99-02, Rev. 5 seems to differentiate the extent of demonstrating notification between operations simulator evaluations and drills. This is also discussed in a previous FAQ 202.

What extent of simulation is required to “demonstrate sufficient knowledge to perform actual notification”? Should “demonstration of their ability to use the equipment” be applied to operations simulator evaluations?

In the simulator evaluations in question, the simulator scenario was developed to have the instructor role-play as the Shift Security Supervisor and did not require any participant to demonstrate use of the phone if security personnel were not available. If these instances do not meet the intent for demonstrating sufficient knowledge of performing notifications and there were no errors made by the participants, should these opportunities be counted in the performance indicator as failures?

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

The NRC has concluded that the opportunities are failures due to not demonstrating the use of phone equipment.

Potentially relevant existing FAQ numbers

FAQ 202 dated 8/30/2000: Added the current wording on page 46 lines 13 – 15 to clarify how notification should be demonstrated during drills vs. operator simulator training.

FAQ 408 dated 2/23/2006: Addresses the question of how programmatic issues are dealt with in the DEP indicator. Issues that do not indicate actual performance are not counted as failures.

<u>Response Section</u>

Proposed Resolution of FAQ

During operator simulator training, personnel filling a non-key position for making a phone call to offsite agencies may not be available. In these instances where the Shift Manager (Emergency Director) and the Shift Communicator do not perform the notification phone call, it is acceptable to demonstrate the notification process up to the point of filling out the appropriate forms and providing the completed notification forms to a person role-playing as the phone-talker. By doing this, the key personnel are demonstrating knowledge of the notification process and simulating turnover to appropriate personnel assigned to complete the phone call(s). Additional time may need to be added to the notification time in order to simulate use of the notification equipment.

For those drills or simulator training scenarios that, after the fact, are determined not to sufficiently demonstrate classification, declaration, or notification due to limited extent of play; they should not be counted for the DEP indicator going forward. They should not be counted as failed opportunities, since this does not reflect performance of the emergency response personnel, but a programmatic deficiency.

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

NEI 99-02, Rev. 5 page 45, lines 39 – 42:

Current wording is italicized, proposed additions are underlined.

Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. <u>It is recognized that key control room positions may not perform the actual communication with offsite agencies as part of the notification process. Personnel filling non-key positions for contacting offsite agencies (phone-talker) may not be available during simulator training. Therefore, "demonstrating sufficient knowledge" includes demonstrating knowledge of the notification process and interface with persons (actual or evaluator role-playing) assigned to contact offsite agencies using equipment (phone-talker). When assessing timeliness of notification in these cases, an appropriate amount of time should be added to the time the notification form is provided to the person role-playing the phone talker, accounting for the additional steps that would have been needed to use the equipment and make contact with the first agency.</u>

FREQUENTLY ASKED QUESTION

Plant: N/A
Date of Event: N/A
Submittal Date: October 15, 2009
Licensee Contact: Roy Linthicum
NRC Contact: John Thompson, 301 415-1011, john.thompson@nrc.gov

Performance Indicator: Mitigating System Performance Indicator

Site-Specific FAQ? **NO**

FAQ requested to become effective: NA

<u>Question Section</u>

NEI guidance needing interpretation/revision:

NEI 99-02, Revision 5, Appendix F, Section F.1.2.1:

To address the problem of having too frequent baseline revisions, the staff is proposing to clarify the definition of maintenance program philosophy and the addition of a requirement to ensure that changes in the UA baseline are consistent with the unavailability assumptions contained in the PRA.

Basis for Revising NEI 99-02, Appendix F, Section f 1.2.1

Section F1.2.2 states that, "The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions." The point of changing the planned unavailability values is to account for philosophy changes to the on-line maintenance or preventive maintenance program.

As this UA baseline definition includes all non-failure activities, the concept of making changes to the UA baseline tied solely to the maintenance program philosophy appears to have created inconsistencies in the implementation of maintenance program philosophy changes. It is the staff's expectation that the performance or condition of the SSCs is effectively controlled by preventive maintenance and testing programs (a maintenance rule expectation). These programs and condition monitoring activities should be periodically evaluated to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs. Changes to the maintenance program philosophy refer to changes to the preventive maintenance and testing programs. This interpretation is consistent with the definition of Maintenance contained in Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance states: "For the purposes of the maintenance rule, maintenance activities are as described in the "Final Commission Policy Statement on Maintenance of Nuclear Power Plants. This definition is very broad and includes all activities associated with the planning, scheduling, accomplishment, post-maintenance testing, and returning to service activities for surveillances and preventive and corrective maintenance." Other additions of unplanned unavailability, such as equipment modifications, except as discussed below, or responses to degraded conditions, are not considered to be a change in maintenance program philosophy. Changes to baseline unavailability for equipment modifications are allowed only if the modification is consistent with the assumptions in the PRA that were used to develop the MSPI Birnbaum values and are not already reflected in the MSPI UA baseline. That is, the unavailability values contained in the PRA include unavailability hours consistent with those needed for the proposed modification, and current maintenance and testing programs; and the hours in the MSPI UA baseline do not reflect this total unavailability. If the MSPI baseline is adjusted as a result of a modification, the MSPI baseline changes should be removed at the conclusion of the 3-year monitoring period that encompasses the modification.

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004 and may not be fully consistent with current practices. However, it is expected that changes to baseline unavailability will reflect the appropriate balancing of preventing failures of SSCs against the objective of minimizing unavailability of SSCs and, as such, the unavailability should not be increasing with time unless a maintenance program philosophy change has been implemented.

Event or circumstances requiring guidance interpretation:

Recommended Changes

Change Section F1.2.2 (lines 35 to 41) from:

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance. These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.)

To:

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance. These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.) Prior to implementation of an adjustment to the planned unavailability baseline value, the impact of the adjusted values on all MSPI PRA inputs should be assessed. A change to the PRA model and associated changes to the MSPI PRA inputs values is required prior to changing the baseline unavailability if:

$\Delta CDF > 1E\text{-}8$

Where:

$\Delta CDF_{baseline} = \sum(\Delta UA_i * Birnbaum_i)$

$\Delta UA_i = UA_{current} - UA_{baseline}$ for segment i

$UA_{current}$ = proposed unavailability (expressed as a probability) to be used as the new baseline

$UA_{baseline}$ = the base unavailability (expressed as a probability) for 2002 – 2004

$Birnbaum_i$ = Birnbaum value of segment i

The following changes are considered a "change in plant maintenance philosophy:"

- A change in frequency or scope of a current preventative maintenance activity or surveillance test.
- The addition of a new preventative maintenance activity or surveillance test.
- The occurrence of a periodic maintenance activity at a higher or lower frequency during a three year data window (e.g., a maintenance overhaul that occurs once every 24 months will occur twice 2/3 of the time and once 1/3 of the time). If the unavailability hours required for the additional maintenance activity is included in the PRA modeled unavailability, the baseline unavailability can be changed without further assessment.
- Planned maintenance activities that occur less than once every 3 years (e.g., 5 or 10 year overhauls). If the unavailability hours required for the additional maintenance activity is included in the PRA modeled unavailability, the baseline unavailability can be changed without further assessment.
- The performance of maintenance in response to a condition-based preventive maintenance activity.
- Performance of an on-line modification that has been determined to be consistent with the unavailability values contained in the PRA in that the PRA includes unavailability hours for the proposed modification, and current maintenance and testing programs; and the hours in the MSPI UA baseline do not reflect this total unavailability.

The following changes are not considered a "change in plant maintenance philosophy:"

- The performance of maintenance in response to a degraded condition (even when it is taken out of service to address the degraded condition) unless this action is in response to a condition-based preventive maintenance activity.
- Planned maintenance activity that exceeds its planned duration.
- The performance of an on-line modification that do not meet the change in plant maintenance philosophy online modification criterion.

Note: Condition-based maintenance consists of periodic preventive maintenance tasks or on-line monitoring of the health or condition of a component (e.g., vibration analysis, oil analysis, MOVAT) and predefined acceptance criteria where corrective action is to be taken on exceeding these criteria. Condition-based maintenance does not include discovery of a degraded condition as a result of actions that are outside of the maintenance programs.

FREQUENTLY ASKED QUESTION

Plant: N/A
Date of Event: N/A
Submittal Date: August 11, 2009
Licensee Contact: Ken Heffner, 919-546-5688, kmh@nei.org
NRC Contact: John Thompson, 301 415-1011, john.thompson@nrc.gov

Performance Indicator: Mitigating System Performance Indicator

Site-Specific FAQ? **NO**

FAQ requested to become effective: April 1, 2010.

Question Section

An industry practice (used by some licensees for some equipment) is to consider equipment potentially "available," upon completion of maintenance but prior to the performance of the post maintenance test (PMT). This determination of availability is typically performed independent of operations personnel, and is made after the completion of the PMT. If the equipment passes its PMT, the status of the equipment between the completion of maintenance and the PMT is scored for MSPI purposes as "available." This approach creates the potential for inconsistency with the treatment of recovery actions to restore the monitored functions where explicit guidance is provided for recovery from testing and operational alignments but not from maintenance. The current guidance associated with the transition between unavailability to availability results in the potential for limited operator awareness, the potential for non-conservative treatment of equipment reliability and the potential for regulatory inconsistency.

NEI guidance needing interpretation/revision:

There is no explicit guidance in NEI 99-02 or NUMARC 93-01 on requirements for scoring the transition from an unavailable state to an available state. Although industry guidance for the recovery of testing or operational alignment could be considered a minimum set of requirements, as these requirements are related to the determination of equipment availability, it appears that application of this guidance to post-maintenance return to service is not a typical practice.

Basis for Revising NEI 99-02, Appendix F, Section f 1.2.1

Lack of Clear Guidance

Unlike operability, recovery of testing or operational alignment (NEI 99-02 Revision 5, Section 1.2.1), and treatment of test-related human errors (Industry White Paper), there is no explicit guidance in NEI 99-02 or NUMARC 93-01 on requirements for scoring the transition from an unavailable state to an available state. One significant difference between the test/operational alignment recovery, and post-maintenance return to service, is the extra failure potential that exists in the latter case, owing to the maintenance action's possible inefficacy. As a result, more requirements, not fewer, would need to be met in order to justify a conclusion of "availability." The present lack of clear guidance results in the potential for scoring the transition from an unavailable state to an available state based on the use of a post-maintenance decision process in which availability is considered to commence on removal of clearance tags, independent of operations. Such a practice does not meet the staff's expectations.

Potential for Limited Operator Awareness

The industry's white paper on this subject dated December 10, 2008 states that most of the licensees contacted use a process in which operators determine "operability" while other personnel (usually system engineers) determine "availability." The paper further states that this determination is made several days or weeks after the SSC was declared operable. The paper also states that most (but not all) licensees do not credit the availability of a SSC, in this available/not operable state, in their online risk assessment.

A logical conclusion is that plant operations is largely decoupled from the process of determining the degree of credit that is taken for the mitigation capability of these monitored components. This decoupling increases the staff concern regarding the industry presumption that recovery of the equipment (if not readied for operation or aligned for auto-start) at the time it is considered transferred for the unavailable to available state is so likely that additional unavailability time does not need to be counted.

Potential for Degraded Equipment Reliability

There are two key considerations associated with equipment reliability during the "available" / not operable state: (1) transition point from unavailable to available, and (2) role of the post-maintenance test.

Transition Point from Unavailable to Available

Although this is not stated explicitly by industry, the staff believes that the transition point used by industry is the time at which the clearance tags are logged as being removed. However, as noted above, it is the staff's understanding that the removal of these tags does not necessarily mean that the equipment is aligned and fully functional. The equipment may require additional alignments in accordance with the appropriate operating instructions (e.g., system refilling and venting may be required) prior to being returned to service. In addition, the equipment controls may remain in pull-to-lock pending completion of equipment line-ups and the post-maintenance tests. If operators are aware that the equipment has not been tested, they are less likely to initiate manual recovery actions. The criterion for determining "availability" should be that restoration actions are virtually certain to succeed. This criterion corresponds to the criterion used for restoration following testing.

Post Maintenance Testing

Equipment adjustments or tuning may occur during the PMT. Such adjustments are unlikely to be reported as a PMT failure, but may improve the reliability of the equipment.

Calculated Unavailability

Industry has provided a white paper that demonstrates that the current industry approach is correct *given certain assumptions*. These assumptions are:

1. The transition point from an unavailable state to an available state represents a transition to a return to service condition where the system is aligned for operations, and operations is aware that it is aligned and that it will automatically start on a valid starting signal or can be promptly restored.

2. No equipment adjustments or tuning occur during the PMT.

Under these conditions, the calculations presented by industry appear correct.

<u>Potential for Inconsistency in the ROP</u>

The lack of guidance on determining the “available” / not operable state and the noted variability in this determination lead to inconsistency in the MSPI indicators, which can result in a reduction of public confidence.

Event or circumstances requiring guidance interpretation:

Section F.1.2.1. Actual Train Unavailability

The definition for “Train unavailable hours” states:

Page F-5 Lines 18 to 22

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

Recommend changing to:

“The hours the train was not able to perform its monitored function while critical. Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train’s monitored functions. In all cases, a train that is considered to be OPERABLE is also considered to be available. Trains that are not Operable must be returned to service in order to be considered available. Unavailability must be by train; do not use average unavailability for each train because trains may have unequal risk weights.”

Return to Service: Return to service is the transition from unavailable to available. A train is “returned to service” when the following conditions are met: clearance tags have been removed, the train 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 the result of the unavailability period, and operators concur that the train 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.

Page F-6 Line 35 to F-7 Line 6

Under the heading “Credit for Operator Recovery Actions to Restore the Monitored Functions”

1. During testing or operational alignment:

“Unavailability of a monitored function during testing or operational alignment need not be included if the test or operational alignment configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a designated operator stationed locally for that purpose, Restoration actions must be contained in a written procedure, must by uncomplicated (a single action or a few actions), must be capable of being restored in time to satisfy PRA success criteria, and must not require diagnosis or repair. Credit for …"

Change to

1.During testing, operational alignment or return to service:

"Unavailability of a monitored function during testing, operational alignment or return to service need not be included if the test or operational alignment configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a designated operator stationed locally for that purpose, Restoration actions must be contained in a written procedure, must by uncomplicated (a single action or a few actions), must be capable of being restored in time to satisfy PRA success criteria, and must not require diagnosis or repair. Credit for …"

Section F 2.2.2 Failures

Recommend adding explanatory text to the following definitions:

Page F-25 Lines 21 to 23:

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 (PMTs), unless the cause of failure was independent of the maintenance performed. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Page F-26 Lines 1 to 5:

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 purposed (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Page F-26 Lines 7 to 9

EDF 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. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Page F-26 Lines 11 to 13

Pump failure on demand: A failure to start and run for at least one hour is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Page F-26 Lines 15 to 17

Pump failure to run: Given that it has successfully started and run for an hour, a failure of a pump to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Page F26 Lines 19 to 21

Valve failure on demand: A failure to transfer to the required monitored state (open, close, or throttle to the desired position as applicable) is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Page F26 Lines 23 to 25

Breaker failure on demand: A failure to transfer to the required monitored state (open or close as applicable) is counted as failure on demand (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. Include all failures that result from a non-PMT demand following return to service. If a PMT failure occurs following return to service and was dependent of the maintenance performed, then this failure is excluded and the train, during the period from the completion of the maintenance activity to the declaration of return to service, is counted as unavailable.)

Industry Response to the FAQ:

Industry comments have been considered and incorporated into this proposal.

Plant: Generic FAQ
Date of Event: N/A

Submittal Date: October 15, 2009

Licensee Contact: Jeff Thomas **Tel/email:** 704-382-3438/jeff.thomas@duke-energy.com

NRC Contact: John Thompson **Tel/email:** 301-415-1011/john.thompson@nrc.gov

Performance Indicator:

IE03, Unplanned Power Changes Per 7,000 Critical Hours

Site-Specific FAQ (Appendix D)? Yes or No

No

FAQ requested to become effective when approved?

Yes

<u>Question Section</u>

NEI 99-02 Rev. 6 Guidance needing interpretation (include page and line citation):

NEI 99-02 (Page 14, Lines 2-4) states that the key element to be used in determining whether a power change should be counted as part of the indicator is the 72 hour period and not the extent of the planning that is performed between discovery of an off-normal condition and initiation of the power change. The 72 hour period ensures that unplanned power changes are counted in the indicator and allows sufficient time, when immediate corrective action is not required, to assess the plant condition, recognize the potential need or desire for a power change, and prepare, review, and approve the necessary work orders and procedures which are necessary to implement the power change.

Given the above, it is incumbent upon licensees to provide objective evidence that supports not counting unplanned power changes of more than 20% as part of the indicator. Specifically, licensees should have documentation that identifies when the off-normal condition was discovered and when the power change of more than 20% was initiated. Consistent with NRC Inspection Procedure 71151, "Performance Indicator Verification," such objective evidence may include logs, troubleshooting plans, meeting minutes, corrective action program documents, or similar type documentation.

NEI 99-02 should be revised to (1) stress the importance of providing objective evidence that supports not counting unplanned power changes as part of the indicator, (2) improve readability by grouping examples of occurrences that would be (would not be) counted against the indicator, and (3) improve guidance regarding slowly degrading conditions (Page 16, Lines 4-12).

Event or circumstances requiring guidance interpretation:

FAQ 447 emphasized the need for clarification

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

N/A

Potentially relevant existing FAQ numbers

FAQ 447

<u>Response Section</u>

Proposed Resolution of FAQ

NEI 99-02 should be revised to (1) stress the importance of providing objective evidence that supports not counting unplanned power changes as part of the indicator, (2) improve readability by grouping examples of occurrences that would be (would not be) counted against the indicator, and (3) improve guidance regarding slowly degrading conditions (Page 15, Lines 24-32).

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

See Attached

UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS

Purpose

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

Indicator Definition

The number of unplanned changes in reactor power greater than 20% of full-power, per 7,000 hours of critical operation excluding manual and automatic scrams.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of unplanned power changes, excluding scrams, during the previous quarter

- the number of hours of critical operation in the previous quarter

Calculation

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

$$value = \frac{(total\ number\ of\ unplanned\ power\ changes\ over\ the\ previous\ 4\ qtrs)}{total\ number\ of\ hours\ critical\ during\ the\ previous\ 4\ qtrs}\ x\ 7{,}000\ hrs$$

Definition of Terms

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

Clarifying Notes

The value of 7,000 hours is used because it represents one year of reactor operation at about an 80% availability factor.

If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is displayed as N/A because rate indicators can produce misleadingly high values when the denominator is small. The data elements (unplanned power changes and critical hours) are still reported.

The 72 hour period between discovery of an off-normal condition and the corresponding change ~~in power level of greater than 20% of full power to resolve and the corresponding change~~ in power level is based on the typical time to assess ~~prepare for a planned power change. It includes time to assess~~ the plant condition, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews, to effect a repair. The key element to be used in determining whether a power change should be counted as part of this indicator is the 72-hour period and not the extent of the planning that is performed between the discovery of the condition and initiation of the power change.

~~recognizing the possible need for a change in power level of greater than 20% and completion of the power change. The licensee should have objective evidence to demonstrate when the possible need for the downpower was recognized such as logs documenting actions required by Technical Specifications, troubleshooting plans, meeting minutes, corrective action program entries, or similar type documentation.~~
Given the above, it is incumbent upon licensees to provide objective evidence that identifies when the off-normal condition was discovered and when the power change of more than 20% was initiated. Such objective evidence may include logs, troubleshooting plans, meeting minutes, corrective action program documents, or similar type documentation.

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

- Power reductions that exceed 20% of full power and are not part of a planned and documented evolution or test. Such power changes may include those conducted in response to equipment failures or personnel errors or those conducted to perform maintenance.
- Runbacks and power oscillations greater than 20 % of full power. A power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% should be counted as two separate PI events, unless the power restoration is implemented using approved procedures. For example, an operator mistakenly opens a breaker causing a recirculation flow decrease and a decrease in power of greater than 20%. The operator, hearing an alarm, suspects it was caused by his action and closes the breaker resulting in a power increase of greater than 20%. Both transients would count since they were the result of two separate errors (or unplanned/non-proceduralized action).
- Unplanned downpowers of greater than 20% of full power for ALARA reasons

Examples of occurrences that are <u>not</u> counted include the following:

- Planned power reductions (anticipated and contingency) that exceed 20% of full power and are initiated in response to an off-normal condition discovered at least 72 hours before initiation of the power change.
- Unanticipated equipment problems that are encountered and repaired during a planned power reduction greater than 20% that alone could have required a power reduction of 20% or more to repair.
- Apparent power changes that are determined to be caused by instrument problems.
- If conditions arise that would normally require unit shutdown, and an NOED is granted that allows continued operation before power is reduced greater than 20%, an unplanned power change is not reported because no actual change in power greater than 20% of full power occurred. However, a comment should be made that the NRC had granted an NOED during the quarter, which, if not granted, may have resulted in an unplanned power change.

- Anticipatory power reductions intended to reduce the impact of external events such as hurricanes or range fires threatening offsite power transmission lines, and power changes requested by the steam load dispatches.
- Power changes to make rod pattern adjustments
- Power changes directed by the load dispatcher under normal operating conditions due to load demand, for economic reasons, for grid stability, or for nuclear plant safety concerns.

Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, animal intrusion, environmental regulations, or frazil icing) may qualify for an exclusion from the indicator. The licensee is expected to take reasonable steps to prevent intrusion of animals, marine debris, or other biological growth from causing power reductions. Intrusion events that can be anticipated as part of a maintenance activity or as part of a predictable cyclic behavior would normally be counted, unless the downpower was planned 72 hours in advance or the event meets the guidance below.

In order for an environmental event to be excluded, any of the following may be applied:

- If the conditions have been experienced before and they exhibit a pattern of predictability or periodicity (e.g., seasons, temperatures, weather events, animals, etc.), the station must have a monitoring procedure in place or make a permanent modification to prevent recurrence for the event to be considered for exclusion from the indicator. If monitoring identifies the condition, the licensee must have implemented a proactive procedure (or procedures) to specifically address mitigation of the condition before it results in impact to operation. This procedure cannot be a general Abnormal Operating Procedure (AOP) of Emergency Operating Procedure (EOP) addressing the symptoms or consequences of the condition (e.g., low condenser vacuum); rather, it must be a condition-specific procedure that directs actions to be taken to address the specific environmental conditions (e.g., jellyfish, gracilaria, frazil ice, etc.)
- If the event is predictable, but the magnitude of the event becomes unique, the licensee must take appropriate actions and equipment designed to mitigate the event must be fully functional at the time of the event to receive exclusion.
- Environmental conditions that are unpredictable (i.e., lightning strikes) may not need to count if equipment designed to mitigate the event was fully functional at the time of the event.
- Downpowers caused by adherence to environmental regulations, NPDES permits, or ultimate heat sink temperature limits may be excluded from the indicator.

The circumstances of each situation are different. In all cases, the NRC Region and Resident Inspectors should evaluate the circumstances of the power change, and if in disagreement with the licensee's position, the event should be identified in an FAQ so that a decision can be made concerning whether the power change should be counted. If the event is truly unique, an FAQ should be submitted unless the NRC Region and Resident Inspectors agree with the licensee's position.

Licensees should use the power indication that is used to control the plant to determine if a change of greater than 20% of full power has occurred.

If a condition is identified that is slowly degrading and the licensee prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have elapsed since the condition was first identified, the power change does not count. If however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count. If the licensee has previously identified a slowly degraded off-normal condition but has not prepared plans recognizing the potential need to reduce power when the condition reaches predefined limits, then a sudden degradation of that condition requiring rapid response would constitute a new off-normal condition and therefore, a new time of discovery.

Off -normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only. However, if the cause of the downpower(s) and the scram are different, an unplanned power change and an unplanned scram must both be counted. For example, an unplanned power reduction is made to take the turbine generator off line while remaining critical to repair a component. However, when the generator is taken off line, vacuum drops rapidly due to a separate problem and a scram occurs. In this case, both an unplanned power change and an unplanned scram would be counted. If an off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor trip using normal operating procedures, only an unplanned power change is counted.