FAQ 52.1

Submitted 2/14 by Terry F. Syrell
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__Question:__ As defined in NEI 99-02, ***unplanned changes in reactor power*** are changes in reactor power that are initiated less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater that 20% of full power to resolve. The 72 hour period between discovery of an off-normal condition and the corresponding change in power level is based on the typical 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 planning that is performed between the discovery of the condition and the initiation of the power change.

Nine Mile Point Nuclear Station (NMPNS) Unit 1 performed a >20% downpower that commenced on 6/15/04 to swap power supplies on condensate pumps in order to exit a High Pressure Coolant Injection (HPCI) LCO action. The timeline leading up to the downpower is as follows:

- 6/7/04. Condensate Pump 13 is removed from service for planned maintenance to repair gland packing problems. Condensate Pump 13 is part of HPCI train #12. A 15 day LCO is entered for the HPCI train being inoperable.

- 6/10/04. During maintenance, it was determined that the existing pump was unusable. A contingency plan was implemented to replace the existing pump with an old rebuilt pump. A second contingency plan was started by plant personnel to swap out pump power supplies to make Condensate Pump 12 act as a HPCI pump. This would allow the station to exit the LCO and complete pump repairs on a normal schedule. Swapping out power supplies required pump 12 to be removed from service which would require a planned downpower to 45% rated.

- 6/11/04. A Temporary Design Change Package was initiated to swap the HPCI power supplies.

- 6/13/04. The first contingency for installing a rebuilt pump was unsuccessful when the pump failed post-maintenance testing due to high running amps. The station then concentrated on implementing the second contingency plan.

- 6/15/04. The down-power to perform the second contingency plan began. The LCO was exited on 6/17/04.

The resident inspection staff questioned the off-normal condition that caused the power change. They considered the rebuilt pump PMT failure on 6/13/04 as the off-normal condition that resulted in the power change. Since the time from the PMT failure to the downpower was less that 72 hours, the resident inspection staff considered the downpower unplanned.

In evaluating this event for reporting under the NRC ROP PI process, the Licensee concluded that the down-power was planned. The basis for this position is as follows: The initial "off-normal" condition was the degraded gland packing on the Condensate pump. This condition necessitated removal of the pump from service to implement repairs. The pump was removed from service and the appropriate Technical Specification LCO was entered on 6/7/04. It was this "off-normal" condition that ultimately led to the down-power that occurred on 6/15/04. Since the down-power was more that 72 hours after the corrective maintenance evolution was initiated, it was classified as "planned."

Should the power change described above be counted in the ROP Performance Indicator for Unplanned Power Changes per 7,000 Critical?

Proposed Answer (Recommended). No. The degraded gland packing constitutes the "off-normal" condition that ultimately resulted in a down-power. Since the time between the initiation of the corrective maintenance activity and the down-power was >72 hours, the downpower is considered "planned."

Alternate Answer. No. The time that the station recognized that alternate methods of repair might be required and that one of the methods would require a down-power constitutes the "off normal" condition as described in NEI 99-02. Since the time between the initiation of contingency planning and the down-power was >72 hours, the downpower is considered "planned."

FAQ 53.1

Plant: Palo Verde Units 1, 2, and 3
Date of Event: Initial plant operation
Submittal Date: 03/25/2005
Licensee Contact: Duane Kanitz **Tel/email:** (623) 393 5427 / dkanitz@apsc.com
NRC Contact: Greg Warnick **Tel/email:** (623) 393 3737 / gxw2@nrc.gov

Performance Indicator: Mitigating Systems - HPSI Safety System Unavailability

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

FAQ requested to become effective when approved or N/A

Question Section

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

NEI 99-02 revision 2, page 33, lines 8 through 23

Equipment Unavailability due to Design Deficiency

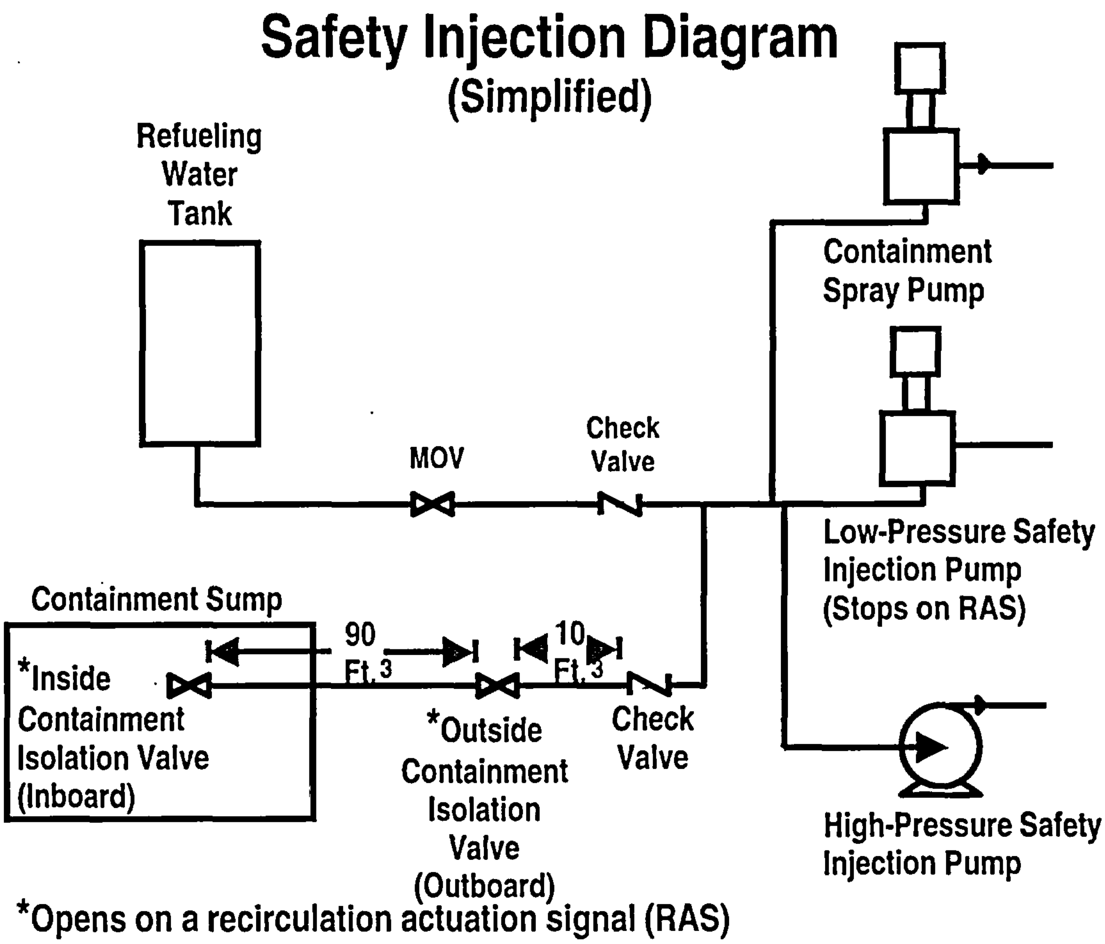
Equipment failures due to design deficiency will be treated in the following manner:

Failures that are capable of being discovered during surveillance tests: These failures should be evaluated for inclusion in the equipment unavailability indicators. Examples of this type are failures due to material deficiencies, subcomponent sizing/settings, lubrication deficiencies, and environmental degradation problems.

Failures that are not capable of being discovered during normal surveillance tests: These failures are usually of longer fault exposure time. These failures are amenable to evaluation through the NRC's Significance Determination Process and are excluded from the unavailability indicators. Examples of this type are failures due to pressure locking/thermal binding of isolation valves or inadequate component sizing/settings under accident conditions (not under normal test conditions). While not included in the calculation of the unavailability indicators, these failures and the associated hours should be reported in the comment field of the PI data submittal.

FAQ 53.1

Event or circumstances requiring guidance interpretation:



In July 2004 Palo Verde Engineering identified a concern that an air pocket existed in the safety injection recirculation suction piping between the containment sump inboard and first check valve downstream of the outboard isolation valves. This section of safety injection suction piping is used following a Loss of Coolant Accident (LOCA) when the system shifts to recirculation mode. Engineering determined that the air in this unfilled section of suction piping could potentially be drawn into the High Pressure Safety Injection (HPSI) pump and the Containment Spray (CS) pumps when the system shifted to recirculation mode, following a Recirculation Action Signal (RAS), and potential affect the operability of both the HPSI and CS system.

During a LOCA, when large quantities of water escape the reactor coolant system, water is injected into the core from the Refueling Water Tank (RWT). When the water level in the RWT gets to an identified low point, a RAS allows reactor cooling to continue by recirculating the water that has collected in the containment sump.

Palo Verde took the initial corrective action of providing a step for operators to open the inboard valve in the event of a loss of coolant accident. This would draw water from the sump and fill the line between the inboard and outboard valves and displace the air in the pipe. Engineering believed that the additional approximately 10 cubic feet of air between outboard isolation valve and the downstream check valve would not prevent water flow through the HPSI and CS systems.

To mitigate the need for operator action and place the units in a safer condition, the sumps and the entire length of pipe between the sump and the safety injection pumps were filled to remove any air pockets. Palo Verde units 1, 2, and 3 are currently maintained in this condition while Engineering completes its analysis and determines what permanent modifications, if any, are required.

As part of the Palo Verde incident investigation, a very comprehensive evaluation was performed to determine how the system would have operated if called upon and determine the significance of the design configuration deficiency. The evaluation included a scale model test and a full scale test. The tests were performed in two distinct steps. First, the scale model test was performed to demonstrate that the behavior of the air in the piping could be determined. This test was performed at Fauske and Associates. Once the behavior of the transient was determined and verified through sensitivity testing, the output of the scale model test was "scaled up" and used as an input to the full scale testing performed at Wyle Laboratories in December 2004. The full scale test was performed to determine the impact of the flow of water and air on the performance of the actual pumps used in the plant.

Based the tests and analyses, Palo Verde concluded that under certain accident scenarios, the HPSI system may not have been able to deliver sufficient flow to perform the required system safety function and therefore was considered inoperable from initial plant startup. However, the CS system was able to perform the required system safety functions and was considered operable. The incident investigation determined that several causes contributed to the condition which included:

> A breakdown in communicating the design requirement to the end user in that the documents used as references for writing the operating and test procedures did not include the requirement to maintain the sump line in a filled condition.
>
> The Palo Verde Technical Specifications only required verifying full the discharge piping and did not mention the suction piping.
>
> The design of the system did not facilitate filling this section of piping.

Because the engineering evaluation had not yet been completed, Palo Verde included the following notes in the third quarter 2004 NRC performance indicator submittal for the HPSI and Residual Heat Removal (RHR) systems respectively:

> Engineering evaluation of HPSI unavailability due to air in containment recirculation sump piping is pending.
>
> Engineering evaluation of RHR unavailability due to air in containment recirculation sump piping is pending.

In the fourth quarter 2004 NRC performance indicator submittal, after the engineering evaluation results were known, Palo Verde included the following notes with the HPSI and RHR system unavailability data:

> An engineering evaluation of HPSI unavailability due to air in the containment recirculation sump piping determined that the HPSI system may not have been able to perform its safety function in response to certain accident scenarios. The deficiency was not capable of being discovered during normal surveillance testing and as such is a design deficiency. The design deficiency has existed since initial plant operation. The condition is being evaluated under the NRC's Significance Determination Process and the associated fault exposure hours are not included in the calculation of the unavailability indicator in accordance with the provisions of NEI 99-02, "Equipment Unavailability due to Design Deficiency."
>
> An engineering evaluation of RHR unavailability due to air in the containment recirculation sump piping determined that the RHR system was able to perform its intended safety function. No design deficiency existed. As such, no fault exposure hours are included in the calculation of the unavailability indicator.

No fault exposure hours were reported in the data that affected the performance indicator for the HPSI system because, as indicated in the submitted note, Palo Verde considered this a design deficiency that existed since initial plant startup. The condition was not capable of being discovered during normal surveillance testing because Palo Verde intentionally operated with the containment suction line unfilled and the Palo Verde Technical Specifications only required that the HPSI pump discharge piping be verified full. There are leak rate surveillance tests and valve stroke surveillance tests performed on the inboard containment sump suction valve. However, since Palo Verde intentionally operated the system with the suction piping unfilled and the Palo Verde Technical Specifications had no requirement to verify that the suction piping was full, the leak rate and valve stroke surveillance testing would only verify that the inboard containment sump valve seated tightly. The testing results would not discover that the HPSI system was inoperable as a result of the containment sump suction piping being left in an unfilled condition.

While Palo Verde was conducting the incident investigation and engineering evaluation, the NRC performed a special inspection in response to the discovered design configuration deficiency. The NRC characterized the condition as an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." The finding was further characterized as more than minor with potential safety significance (i.e. greater than green) based on a Significance Determination Process, Phase 3 analysis because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events.

The change in core damage frequency value based on assumptions from the NRC SPAR models was 2.5e-5 (which equates to a yellow finding). The change in core damage frequency value based on assumptions using Palo Verde's PRA was 7.0e-6 (which equates to a white finding.)

Should fault exposure hours be included in the performance indicator calculation for HPSI?

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

The NRC resident/region do not agree that the condition as described can be considered an "equipment failure" as referenced in NEI 99-02 revision 2, page 33, line 10. Furthermore, the NRC resident/region do not agree that Palo Verde was unable to discover the condition during the performance of normal surveillance tests (i.e. the leak rate and valve stroke surveillance testing would have been able to discover that operating HPSI system with containment sump suction line unfilled would have prevented the HPSI system from performing the system safety function by either performance of the testing or during the process of revising the test procedures.) Note that in 1992, the leak rate and valve stroke test procedures were revised to drain and operate with the containment suction piping unfilled following performance of the leak rate test.

Therefore, fault exposure hours must be reported and included in the HPSI performance indicator calculation.

Potentially relevant existing FAQ numbers: 316 and 348

Response Section

Proposed Resolution of FAQ

The condition should be treated as equipment unavailability due to a design deficiency in accordance with the provisions of NEI 99-02 revision 2 and approved FAQs 316 and 348. No fault exposure hours need be including in the data for calculating the performance indicator value because the condition is more amenable to evaluation through the NRC's Significance Determination Process. A note should be placed in the comment section identifying the condition and the associated fault exposure hours should be reported in the comment field. (A statement acknowledging that the condition existed since initial start up adequately should suffice in satisfying the intent of specifying a discreet number of fault exposure hours.)

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

Fault Exposure Unavailability due to Design or Construction Deficiency

Equipment failures or discovered conditions due to design or construction deficiencies will be treated in the following manner:

Failures that are capable of being discovered during normal surveillance tests: These failures should be evaluated for inclusion in the equipment unavailability indicators. Examples of this type are failures due to material deficiencies, subcomponent sizing/settings, lubrication deficiencies, and environmental degradation problems.

Failures that are not capable of being discovered during normal surveillance tests: These failures are usually of longer fault exposure time. These failures are amenable to evaluation through the NRC's Significance Determination Process and are excluded from the unavailability indicators. Examples of this type are failures due to pressure locking/thermal binding of isolation valves or inadequate component sizing/settings under accident conditions (not under normal test conditions). While not included in the calculation of the unavailability indicators, these failures and the associated hours should be reported in the comment field of the PI data submittal.

FAQ 53.2

Plant: Vogtle
Date of Event:
Submittal Date: 4/28/2005
Licensee Contact: ______________________ **Tel/email:** ________________
NRC Contact: ______________________ **Tel/email:** ________________

Performance Indicator: Drill/Exercise Performance

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved

Event Description

During a recent drill at Vogtle, 9 minutes after an EAL condition had been met, the shift manager and shift supervisor were still debating whether a "transient" had occurred and if the plant was "stable", in order to make a decision on the EAL. The controller than asked "Is the plant stable?" The shift manager acknowledged the question and declared an Alert. In its critique, the licensee identified that the controller may have interfered with the decision, and therefore, determined that no classification opportunity existed. The licensee claims that the opportunity for the shift manager to independently declare the event was removed when the controller "asked a question."

Question

If during the performance of a DEP PI opportunity, a controller intervenes in a way (e.g., coaching, prompting) such that the action interferes with an individual making an independent and correct classification, notification, or PAR, shall the DEP PI opportunity be considered a failure, success or a non-opportunity?

Proposed Response

If a controller intervenes (e.g., coaching, prompting) with the performance of an individual to make an independent and correct classification, notification, or PAR, then that DEP PI opportunity shall be considered a failure.

Proposed Rewording of Guidance for Inclusion in Next Revision

EP DEP PI change to NEI 99-02, rev 3, pg 82, due to incorporating FAQ 53.2

If the expected classification level is missed because an EAL is not recognized within 15 minutes of availability, but a subsequent EAL for the same classification level is subsequently recognized, the subsequent classification is not an opportunity for DEP statistics. The reason that the classification is not an opportunity is that the appropriate classification level was not attained in a timely manner.

If a controller intervenes (e.g., coaching, prompting) with the performance of an individual to make an independent and correct classification, notification, or PAR, then that DEP PI opportunity shall be considered a failure.

Failure to appropriately classify an event counts as only one failure: This is because notification of the classification, development of any PARs and PAR notification are subsequent actions to classification. Similarly, if the same error occurs in follow-up notifications, it should only be considered a missed opportunity on the initial notification form.

FAQ 54.1

Plant: Catawba Nuclear Station Units 1 and 2
Date of Event: TBD
Submittal Date:
License Contact: Kay Nicholson Tel/email: 803-831-3237
kenichol@duke-energy.com
NRC Contact: Tel/email:

Performance Indicator: Mitigating Systems Cornerstone - Safety System Unavailability

Site-Specific FAQ (Appendix D)? YES

QUESTION SECTION

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

NEI 99-02, revision 3, page 27, lines 28 through 33

Event of Circumstances requiring guidance interpretation:

Catawba Nuclear Station (CNS) plans to refurbish the "A" and "B" trains of the Nuclear Service Water System (NSWS) supply header piping. This refurbishment will occur with both Unit 1 and Unit 2 at 100% power operation. CNS has submitted a Technical Specification (TS) change for NRC approval to provide for a completion time sufficient to accommodate the overhaul hours associated with the refurbishment project.

The proposed TS changes will allow the "A" and "B" Nuclear Service Water System (NSWS) headers for each unit to be taken out of service for up to 14 days each for system upgrades. This will be a one time evolution for each header. System upgrades include activities associated with cleaning, inspection, and coating of NSWS piping welds, and necessary system repairs, replacement, or modifications. It has been estimated that the work required in taking the system out of service and draining the affected portions, will take approximately 1 day. The affected sections of piping will be cleaned which should take approximately 3 - 4 days. After cleaning, this evolution will include inspection and evaluation of the NSWS piping. The inspection results will be evaluated for repairs and/or coatings for the welds. After inspection, the welds in the affected piping will be coated and allowed to cure. This portion should take approximately 6 - 7 days. Upon completion, Operations will be required to fill the NSWS, and perform any necessary post maintenance testing which should take approximately 2 days. Therefore, the total time should run from 12 - 14 days.

CNS desires to apply the overhaul hour exemption to the NSWS supply pipe refurbishment project. The NSWS Improvement plan is divided into three distinct phases. The phase one of the plan specifically targets the stabilization of the welds in the NSWS supply headers. Phase one includes activities associated with cleaning, inspection, and coating of NSWS piping welds, and necessary system repairs, replacement, or modifications. Civil engineering evaluations of the longitudinal and circumferential welds in the supply headers have determined that the first priority area for the initial phase should be main buried 42 inch supply headers. These activities are being done to preclude any further degradation of the affected welds. This will allow the second and third phases of the NSWS Improvement Plan to commence with a predictable and reliable schedule.

Although the NSWS is not a monitored system under NEI 99-02 guidance, its unavailability does affect various systems and components, many of which are considered major components by the definition contained in FAQ 219 (diesel engines, heat exchangers, and pumps). The specific performance indicators affected by unavailability of the NSWS are Emergency AC, High Pressure Safety Injection, Residual Heat Removal, and Auxiliary Feedwater. NEI 99-02 states that "overhaul exemption does not normally apply to support systems except under unique plant-specific situations on a case-by-case basis. The circumstances of each situation are different and should be identified to the NRC so that a determination can be made. Factors to be taken into consideration for an exemption for support systems include (a) the results of a quantitative risk assessment, (b) the expected improvement in plant performance as a result of the overhaul activity, and (c) the net change in risk as a result of the overhaul activity." The following information is provided in accordance with the NEI guidance.

- QUANTITATIVE RISK ASSESSMENT

Duke Power has used a risk-informed approach to determine the risk significance of taking a loop of NSWS out of service for up to 11 days beyond its current TS limit of 72 hours. The acceptance guidelines given in the EPRI PSA Applications Guide were used as a gauge to determine the significance of the short-term risk increase from the outage extension.

The current PRA model was used to perform the risk evaluation for taking a train of NSWS out of service beyond its TS limit. The requested NSWS outage does not create any new core damage sequences not currently evaluated by the existing PRA model. The core damage frequency contribution from the proposed outage extension is judged to be acceptable for a one-time, or rare, evolution. The estimated increase in the core damage probability for Catawba for each NSWS loop outage ranges from 2.7E-06 for a 2-day extension up to 1.5E-05 for an 11-day extension. Based on the expected increase in overall system reliability of the NSWS, an overall increase in the safety of both Catawba units is expected.

EXPECTED IMPROVEMENT IN PLANT PERFORMANCE

The increase in the overall reliability of the NSWS along with the decreased unavailability in the future because of the pipe repair project will result in an overall increase in the safety of both Catawba units.

NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY

Increased NSWS train unavailability as a result of this overhaul does involve an increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header is out of service for pump refurbishment. Considering the small time frame of the NSWS trains outage with the expected increase in reliability, expected decrease in future NSWS unavailability as a result of the refurbishment project, and the contingency measures to be utilized during the refurbishment project, net change in risk as a result of the overhaul activity is reduced.

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

Not Applicable, NRC currently reviewing license amendment request to revise TS to allow for time necessary to perform overhaul of NSWS.

Potentially relevant FAQ numbers:

FAQ 178 & 219

<u>RESPONSE SECTION</u>

Proposed Resolution of FAQ:

For this plant specific situation, planned overhaul hours for the nuclear service water support system may be excluded from the computation of monitored system unavailability.

Such exemptions may be granted on a case-by-case basis. Factors considered for this approval include (1) the results of a quantitative risk assessment of the overhaul activity, (2) the expected improvement in plant performance as a result of the overhaul, and (3) the net change in risk as a result of the overhaul.

FAQ 55.1

Plant:	Three Mile Island Unit 1		
Date of Event:	N/A (Request for interpretation of system configuration)		
Submittal Date:	April 29, 2005		
Licensee Contact:	Dave Distel	Tel/email:	610-765-5517
NRC Contact:	Javier Brand	Tel/email:	717-948-8270

Performance Indicator: SSU PI MS.01 (Emergency AC Power Systems)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 Guidance needing interpretation:

Section 2.2 of NEI 99-02, Revision 3, 'Clarifying Notes/Planned Unavailable Hours' –"Causes of planned unavailable hours include, but are not limited to, the following:"

Specifically, Page 25, Lines 3 through 9:

> "...testing, unless the test configuration is automatically overridden by a valid start signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (*a single action or a few simple actions*), and must not require diagnosis or repair. Credit for a dedicated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur."

Event or circumstances requiring guidance interpretation:

One of two 100% redundant emergency diesel generators is operating parallel to the offsite source for surveillance testing, or other special testing such as post-maintenance or post-modification testing purposes. The other is OPERABLE and in standby; it starts automatically upon the emergency signal and is annunciated in the control room. A combination of automatic actions, two manual actions in the control room, and a single local manual action are required to fully return the test EDG to emergency mode. The automatic actions occur instantaneously upon an accident signal and consist of an output breaker trip and conversion of the voltage regulator to isochronous (isolated operation) mode. A dedicated operator in the control room, involved with the test, accomplishes the following two manual actions:

1. Return the EDG voltage regulator to automatic mode by turning the selector switch in the control room. This will establish uniform voltage for extended emergency mode operation.

2. Return the EDG governor to its 60 Hz isochronous operating point by adjusting the speed from the control room.

The local EDG operator, involved with the test, who is in radio communication with the control room, accomplishes the following local manual action:

3. Remove the speed droop dialed into the governor at the dial face on the EDG skid by turning the droop knob to the 'zero' position.

These restoration steps are included in the surveillance test procedure and operator training on recognition and restoration is regularly conducted. Engineering analysis and testing will demonstrate that the test EDG and its emergency loads will function acceptably through the period of time when automatic safety-related block loading is occurring. The engine governor and voltage regulator are calibrated to ensure that the EDG response remains within the limits of the engineering analysis. The manual actions must be completed prior to the operators assuming control and manually applying or removing plant loads in order to avoid potentially unacceptable bus frequency and/or voltage changes. These actions are performed after the control room situation has stabilized and are not performed under stressful/chaotic conditions. Through the use of procedures and training, completion of these steps has a virtual certainty of success.

Does the EDG accrue unavailability time when operating parallel to the offsite source?

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

N/A

Potentially relevant existing FAQ numbers:

FAQs 201, 301, and 322

Response Section

Proposed Resolution of FAQ:

The test EDG does not accrue unavailability hours during operation in this case. This is based on the following:

1. Although conducted at two locations, the number of steps to return the test EDG to emergency mode meets the intent of the "few simple actions" threshold of NEI 99-02, Section 2.2.

2. The operator actions are proceduralized and the operators are routinely trained on these steps.

3. Control room and local personnel are available, positioned, and trained to accomplish the required actions.

4. Continuous communication is maintained between the control room and the local operators for the duration of the EDG testing.

5. There is ample time to accomplish the actions such that the operators are not in a stressful and chaotic situation at the time the required actions are to be performed.

6. No troubleshooting is necessary. The single operator reaction to a plant parameter (i.e., the engine frequency adjustment) is performed after the situation has stabilized.
7. The response of the EDG is confirmed via testing and the time period until the actions are completed is supported by sound engineering analysis.
8. The engine governor and voltage regulator are properly adjusted to remain within the limits of the engineering analysis.
9. The three manual actions are virtually certain to be successful.

<u>If appropriate, provide proposed rewording of guidance for inclusion in next revision:</u>

N/A

FAQ 55.2

Plant:	Millstone Unit 3	
Date of Event:	November 14, 2004	
Submittal Date:	July 21, 2005	
Licensee Contact:	D.W. Dodson	Tel/Email: 860-447-1791x2346/David_W_Dodson@Dom.com
NRC Contact:	S.M. Schneider	Tel/Email: 860-444-5394 / SMS2@NRC.gov

Performance Indicator: Mitigating Systems Cornerstone Safety System Unavailability High Pressure Safety Injection

Site Specific FAQ (Appendix D): No

FAQ requested to become effective when approved

Question Section

NEI 99-02 Guidance needing interpretation (including page and line citation)
There are essentially two sections of NEI 99-02 that are being discussed for counting unavailability hours for a Westinghouse 4 Loop High Pressure Safety Injection (HPSI) System for a postulated situation of failure of an intermediate head safety injection pump. The Millstone 3 HPSI system consists of the high head safety injection system (i.e., charging system (CHG)) and intermediate head safety injection system (i.e., SIH). The Recirculation Spray System (RSS) pumps take suction from the containment sump upon depletion of the RWST, and discharge to the suction of the charging pumps and the SIH pumps. Millstone believes that during this postulated situation, the RSS system is in its required lineup and is not an alternate system, and, therefore, no unavailability hours would be counted since the HPSI and RSS safety functions would be met.

The first applicable section is Page 29 line 22; A train is available if it is capable of performing its safety function.

- o Page 29 Line 29-31, "Fault exposure hours are not counted for a failure to meet design or technical specifications, if engineering analysis determines the train was capable of performing its safety function during an operational event.

The second applicable section is page 24 lines 11-13; Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems at a given plant that add diversity to the mitigation or prevention of accidents.

Event or circumstances requiring guidance interpretation:
Millstone Unit 3 is a Westinghouse 4 loop plant. Per the definitions in NEI 99-02 Rev. 3 (Page 55 lines 29-39), the HPSI train is considered a 4-train system based on the number of flow paths. Two trains are part of the charging system (high head safety injection) and two are part of the SIH system (intermediate head safety injection).

For Millstone unit 3 the SIH system is a component of the Emergency Core Cooling System (ECCS) and is therefore credited for post-LOCA event mitigation. The SIH system supports initial injection from the Refueling Water Storage Tank (RWST) to the Reactor Coolant System (RCS) cold legs during the injection phase of the event. Within approximately 1 hour, the SIH suction is realigned to the RSS system for cold-leg recirculation, the first phase of post-accident recirculation. The RSS pumps take suction from the containment sump upon depletion of the RWST, and discharge to the suction of the charging pumps and the SIH pumps. RSS is the only system designed to take suction from the containment sump and provide suction boost during the post-accident recirculation phase, therefore it is required for all post-accident recirculation conditions that the SIH and charging systems support. The SIH system also provides hot leg recirculation during the post-LOCA recirculation phase for boron precipitation control in the event of a cold leg break. Realignment to support boron precipitation control is accomplished by realigning the SIH discharge path at approximately nine hours after event initiation. The suction path remains aligned to RSS for the duration that post-accident recirculation is required. The RSS system is monitored under the RHR function. This ECCS subsystem is cross-connected so any RSS pump can supply flow to all the charging and SIH flow paths.

In November 2004 Millstone concluded that a previously identified oil leak on the 'A' SIH pump could have impacted the long term availability of that pump during the period 10/14 to 11/04/04. Based on the observed leak rate, it was calculated that the pump bearing would lose lubrication after approximately 7 days of operation causing the pump to seize. Further review identified that the 'B' SIH pump was similarly impacted by an oil leak from 8/2002 to 4/2003 and would lose lubrication after approximately 15 days of operation causing the pump to seize. The SIH pump would have operated during the injection phase and for an extended period during the recirculation phase. A review of Millstone Unit 3 (MP3) licensing basis documents and relevant regulatory documents did not identify a post accident mission time for ECCS subsystems

A formal engineering evaluation was prepared to support the assessment of historical operability/availability. This evaluation determined that after 6 days the RSS pump alone could provide enough flow through the SIH piping and components (with no change of system alignment) to meet the hot leg recirculation flow requirements with a postulated seized SIH pump. Thus, it was determined that the mission time for the SIH pumps is 6 days. Based on this evaluation, it was determined that the ECCS system was Operable and that the HPSI safety function was available per NEI 99-02.

In summary: Millstone SIH pumps had oil leaks that may have caused the pumps to fail at 7 days or more. The HPSI mission time is 6 days. At the time of postulated failure, during the post-accident recirculation phase, the HPSI safety function will have been satisfied and RSS would be in its required lineup providing its safety function. Therefore, no unavailability hours should be counted for the HPSI or RHR performance indicators. Is Millstone's interpretation of this situation correct?

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

It is the resident inspector's position that the Millstone evaluation improperly credits an alternate system (e.g., RSS) for meeting the HPSI function and that unavailability should be accrued. Millstone believes that during this postulated situation, the RSS system is in its required lineup and is not an alternate system, and, therefore, no unavailability hours would be counted since the HPSI and RSS safety functions would be met.

FAQ 55.2

Potential relevant existing FAQ numbers

FAQ 188 may be relevant in that it implies that when considering use of alternate systems it considers those systems that are not normally aligned within the design basis and would require additional operator action to align if there was a failure.

Response Section

Proposed Resolution of FAQ

The RSS system would be in its required lineup and performing its required safety function. Therefore, it is not considered to be an alternate system. The HPSI safety function would have been met therefore no unavailability hours need to be counted.

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

None

TempNo.	PI	Question/Response	Status	Plant/ Co.
36.9	IE02	Question: During startup activities following a refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations increased as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators. Based on industry operating experience, operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage Licensed Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34) for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience. Does this SCRAM count against the performance indicator for scrams with loss of normal heat removal?	1/22 Introduced 3/25 Discussed. Question to be rewritten and response provided 4/22 Question and response provided 6/16 Discussed 7/22 Discussed 8/18 Discussed 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 Appeal meeting tentatively scheduled for June 2005 6/14 FAQ Appeal Meeting	Millstone 2
		Response: No, this scram does not count against the performance indicator for scrams with loss of normal heat removal. The conditions that resulted in the closure of the MSIVs after the reactor trip were expected for the main turbine startup following rotor replacement. Operator actions for this situation had been incorporated into normal plant procedures.		

TempNo.	PI	Question/Response	Status	Plant/ Co.
50.1	MS01	Question: (APPENDIX D) The Oconee Nuclear Station emergency power is provided by the Keowee Hydro units (KHUs) located within the Oconee Owner Controlled Area. The Keowee hydroelectric station has been in service since 1971, with the last major overhaul performed in 1985. Duke Energy (Duke) is performing significant upgrades and overhaul maintenance to each KHU to ensure future reliability. This work includes replacement of the governor, exciters, and batteries, and weld repair on the turbine blades and discharge ring along with draft tube concrete repair. This FAQ seeks an exemption from counting the planned overhaul maintenance hours for the one-time KHU outages. *Was there NRC approval through an NOED, Technical Specification change, or other means?* An amendment was approved by the NRC to temporarily extend Technical Specification (TS) 3.8.1 Required Action Completion Times to allow significant maintenance and upgrades to be performed. Even though each KHU is being upgraded one at a time, the tasks of isolating and un-isolating the unit being upgraded makes both KHUs inoperable. The approval allows Duke to temporarily extend the 60 hour Completion Time for restoring one Keowee Hydro Unit (KHU) when both are inoperable by 120 cumulative hours over two dual KHU outages. For example, 60 hour + 40 and 60 hours + 80 for a total of 240 hours is allowed during each KHU (KHU1 & KHU2) Refurbishment Outage. KHU 1 has already completed its extended outage using 206 of the 240 allowed hours in the dual KHU outage. The KHU 2 will be performed in January - February 2005 and is expected to use a similar number of hours spread over two dual KHU outages. Even though one KHU is being upgraded at a time, the tasks of isolating and un-isolating the unit being upgraded makes both KHUs inoperable. During the time period when both KHUs are inoperable, both TS 3.8.1 Required Actions C.2.2.5 and H.2 will be entered. Entry into H.2 is relevant to the underground. Only the underground unavailable hours are reported for PI. *Was there a quantitative risk-assessment of the overhaul activity?* A quantitative risk analysis was performed. The analysis showed that the planned configuration was acceptable per Regulatory Guide 1.177 and 1.174. The cumulative core damage probability (CCDP) for each extended KHU outage was calculated to be 4.4E-07. A subset of the extended single unit outage is the two dual KHU outages (which makes the underground path unavailable for the period of time mentioned above.) *What is the expected improvement in plant performance as a result of the overhaul and what is the net change in risk as a result of the overhaul activity?* The net change in risk as a result of the overhaul activity is reduced because of the expected decrease in future Emergency Power unavailability as a result of the overhaul, and the contingency measures to be utilized during the overhaul. During Duke's December 16, 2003, meeting with NRC, the Staff indicated that even though the revised cumulative CDP was in the E-07 range, their guidelines required defense-in-depth measures to be considered in order to approve the LAR. Duke presented defense-in-depth measures credited to offset the additional risks associated with the dual KHU outages during that meeting and in a December 18, 2003 letter. These defense-in-depth measures, which address grid-related events, switchyard-centered events, and weather-related events, are as follows: For grid-related events • A 100 kV dedicated line separated from the grid • A Lee Combustion Turbine (LCT) already running and energizing the standby buses via the 100 kV dedicated line • Two additional LCTs available, either of which can provide the necessary power • One of the two additional LCTs running and available to be connected to the 100 kV dedicated line during the dual KHU outage • A Jocassee Hydro Unit capable of providing power via a dedicated line separated from the grid • Up to three additional Jocassee hydro units, any of which can provide necessary power and be connected to the dedicated line • Standby Shutdown Facility (SSF) remains available as an alternate shutdown method the SSF will be removed from service for its scheduled monthly maintenance, but not during the dual unit outage For switchyard centered events	12/15 Introduced 3/17 Discussed (Have licensee available for next meeting) 4/28 Discussed 5/19 Discussed 5/19 Tentative Approval (NRC to provide revised response)	Oconee

TempNo.	PI	Question/Response	Status	Plant/ Co.
		Response: Yes, the requirements of Appendix D of NEI 99-02 have been met..		
50.5	IE01	Question: On December31, 2004, during Oconee Unit 3 startup, there was an unanticipated change in reactor power from about 3% to 6%. The control room operator was initiating a power increase to 15% to enable putting the turbine online. When the desired power level value was input into the integrated control system (ICS), without awaiting a rate input or the operator placing ICS in Auto, the system unexpectedly started rapidly raising reactor power at the maximum rate. The control room team quickly took action to mitigate the power excursion by reducing the ICS power demand setpoint. The regulating rod group was inserted at normal rod speed by the ICS as it responded to the new demand. Due to normal control system overshoot, the control rods were inserted sufficiently to place the reactor in a shutdown condition. The reason for the unexpected action by the ICS was due to a software error that was introduced during an update to the system during the refueling outage. Upon completion of the transient mitigation response, the control room team decided to complete the reactor shutdown via manual control rod insertion of the remaining rod groups in the normal sequence. The event resulted in a subcritical reactor with power range NIs reading zero due to rod motion properly requested from the ICS in response to operator mitigation of the initial transient and minor power excursion. The definition of "scram" as applied to the initiating events PI IE01 Unplanned Scrams is a rapid insertion of negative reactivity that shuts down the reactor (e.g. via rods, boron, opening trip breakers, etc.) A conservative reading of the definition results in the event meeting the definition of "Unplanned Scram" for the purpose of NRC PIs. However, it is unclear whether normal rod motion at ONS is considered "rapid". Question: Is the reactor shutdown described above considered a "scram" for performance indicator reporting?	1/27 Introduced 3/15 Oconee revision (clarification) of Question 3/17 Discussed 4/28 Discussed 5/19 Discussed	Oconee
		Response: Duke Power does not believe this event constitutes a "scram" per NEI 99-02 because the rod insertion was at the normal speed as opposed to "rapid" insertion via gravity in response to opening the reactor trip breakers. In addition, the event did not challenge or require any critical safety system which is the basis for measuring "scram" events per NEI 99-02. Therefore, the event did not constitute a "scram" because normal rod speed should not be considered "rapid" and the event did not meet the intended scope of events measured by the PI.		